



Minerals Management Service

Evaluation of High Integrity Pressure Protection Systems



Final Report

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ABBREVIATIONS

| | |
|--------|---|
| °F | Degrees Fahrenheit |
| ANSI | American National Standards Institute |
| API | American Petroleum Institute |
| ASME | American Society of Mechanical Engineers |
| AVE | Average |
| AWS | American Welding Society |
| cc | Cubic Centimeter |
| CP | Cathodic Protection |
| CRA | Corrosion Resistant Alloy |
| DCV | Directional Control Valve |
| DNV | Det Norske Veritas |
| E/E/PE | Electrical / Electronic / Programmable Electronic |
| ESD | Emergency Shutdown |
| FAT | Factory Acceptance Testing |
| ft | Foot |
| FWHP | Flowing Wellhead Pressure |
| GoM | Gulf of Mexico |
| GOR | Gas Oil Ratio |
| HBN | Brinell Hardness Number |
| HIPPS | High-Integrity Pressure Protection System |
| HIPV | HIPPS Valve |
| HPT | HIPPS Pressure Transducer |
| HSCM | HIPPS Subsea Control Module |



| | |
|-------|--|
| ID | Internal Diameter |
| IEC | International Electrotechnical Commission |
| ISA | International Society of Automation |
| ISO | International Organization for Standardization |
| ksi | Kilopounds (kips) per Square Inch (1000 psi) |
| LSS | Logic Sub-System |
| MAOP | Maximum Allowable Operating Pressure |
| MD | Measured Depth |
| MeOH | Methanol |
| min | Minute |
| MMS | Minerals Management Service |
| NACE | National Association of Corrosion Engineers |
| OCS | Outer Continental Shelf |
| OREDA | Offshore Reliability Data |
| PFD | Probability of Failure on Demand |
| P&ID | Process and Instrumentation Diagram |
| PLEM | Pipeline End Manifold |
| PLET | Pipeline End Termination |
| psi | Pounds per Square Inch |
| psia | Pounds per Square Inch Absolute |
| PSL | Product Specification Level |
| PSV | Production Shutdown Valve |
| PT | Pressure/Temperature (sensor) |
| PVT | Pressure Volume Temperature |



| | |
|-------|--|
| ROV | Remotely-Operated Vehicle |
| RP | Recommended Practice |
| s | Second |
| SAE | Society of Automotive Engineers |
| SCC | Stress Corrosion Cracking |
| scf | Standard Cubic Foot |
| SCM | Subsea Control Module |
| SCSSV | Surface-Controlled Subsurface Safety Valve |
| SDV | Shut Down Valve |
| SEM | Subsea Electronics Module |
| SIL | Safety Integrity Level |
| SIS | Safety Instrumented System |
| SSC | Sulfide Stress Cracking |
| SSS | Sensor Sub-System |
| stb | Standard Barrel |
| TFL | Through Flowline |
| TRR | Target Risk Reduction |
| TVD | True Vertical Depth |
| USV | Underwater Safety Valve |
| VSS | Valve Sub-System |
| WHSIP | Wellhead Shut-In Pressure |
| WT | Wall Thickness |
| XooY | 'X' out of 'Y' |



1. EXECUTIVE SUMMARY

This work was done by the Granherne subsidiary of Kellogg Brown & Root LLC under contract M08PC20027 for the United States Department of the Interior, Minerals Management Service.

1.1 Background

A number of High Integrity Pressure Protection Systems (HIPPS) have been deployed subsea around the world, but none yet in the United States OCS. Although they are typically viewed as offering purely commercial benefit by allowing for lower pressure – and thus lower cost – pipelines and flowlines, there is a strong case for suggesting that their application may become a technical necessity for high pressure applications in deeper water – conditions that are likely to be found in many future Gulf of Mexico developments.

The loads that can be handled while installing heavy walled pipe for flowlines, pipelines and risers in deep water are limited by the capabilities of the installation vessels. Thus, a safe, regulated means to reduce the pressure rating of such lines would enable the installation of the infrastructure for such deeper and higher pressure developments.

The objective of this group of interrelated studies is to offer in-depth guidance to the MMS on several topics that are critical to regulation of these systems.

1.2 Basis for the Scope of Work

The Scope of Work outlined below is based on interpretation of the MMS' stated goals outlined in the Research Solicitation M08PS00008, namely:

Objective:

The objective of the study was to provide guidance on market research, material selection, industry procedures, codes and other topics as deemed critical to MMS regulation of HIPPS.

Desired Outcome:

Many HIPPS configurations and control schemes exist. Specific areas of concern are:

- HIPPS valve leakage rate requirements
- HIPPS valve response time
- Material selection (especially in the presence of H₂S)



- Length of the fortified section immediately downstream of the HIPPS
- Determination of riser fortification requirements when used with a HIPPS (concern has been expressed that, in extreme water depths, it may be difficult for the pipeline to be designed to a higher pressure rating than the riser).
- Assessment of international standards and current applications and recommendations on regulation for the Gulf of Mexico.

Reason for Research:

- API 17O (HIPPS) has been newly issued but not yet employed.
- HIPPS systems are being viewed as critical to future deepwater development, but experience with these systems in the Gulf of Mexico does not exist.
- While HIPPS may become necessary due to pipeline size and weight, there is a significant amount of risk involved because of the high pressure, high flow rate deepwater wells.
- MMS needs to gain a better understanding of the implications of timing, testing, material selection, and similar issues in order to justify regulatory requirements.

1.3 Section Summaries

1.3.1 Introduction

To capture the various topics the MMS wished to address, the work was divided into an administrative activity, designated CTR 100, and six tasks, CTRs 200 through 700. A brief summary of the subject and conclusions for each task follow with detailed discussions in subsequent sections of the report. Task numbers correspond to section numbers, e.g. Task **200** is summarized in Section 1.3.2 below then later described further in Section **2**.

1.3.2 TASK 200 – HIPPS VALVE LEAKAGE RATE REQUIREMENTS

This topic covers how to perform testing and analysis to demonstrate that HIPPS valves are leak free or to confirm the validity of a deviation request if a leak is noted. To support these discussions and to illustrate some of the variables, a typical HIPPS manifold and flowline system are described including sketches. Sensitivity analyses are performed for leakage testing and flowline packing on a typical system to illustrate effects of relevant variables. The study concludes with considerations that are important for evaluating general deviation requests related to leaking HIPPS valves.



The worst combination of variables for valve leakage testing is that which maximizes the time required for pressure to drop a given amount. This is because a short hold period given the worst combination of variables may not be long enough to exhibit a significant pressure drop given the errors and randomness associated with pressure transducers. Thus, it is recommended that more attention be given to HIPPS valve leakage test calculations involving higher temperatures, lower test chamber pressures, higher test chamber volumes, and higher test fluid GORs. This combination of variables will lead to longer leakage times and poorer leak detection.

The worst combination of variables for flowline packing is that which minimizes the time required for pressure to rise a given amount. It is recommended that more attention be given to flowline packing calculations involving higher initial downstream pressures, lower downstream flowline lengths, and lower production fluid GORs. As illustrated by the analyses, this combination of variables will lead to shorter packing times.

1.3.3 TASK 300 – HIPPS VALVE RESPONSE TIME REQUIREMENTS

This section examines HIPPS valve response time and the resulting impact to the flowline system. Valve response time is the main determinant of the system closure time, one of the three interrelated variables that operators will be required to determine and submit as part of their application for approval along with the High-High trip point and the length of the fortified section.

This section examines two separate but related issues:

1. What needs to be considered to determine the theoretical valve response time for HIPPS valves;

The valve response time determination is affected by factors such as manufacturing tolerance, operating pressure, operational depth, control fluid pressure, rate of control fluid dumping to the sea, and temperature of the valve. These factors are taken into consideration during the design phase of the actuator.

2. What needs to be considered to determine the impact of a given valve response time for HIPPS valves on the HIPPS system.

Restrictions in the flowline leading to a pressure increase and tripping of the HIPPS could be from wax deposits or hydrates. The HIPPS could be triggered if the Emergency Shutdown (ESD) valve is closed or if, due to an operator error, the flowline is inadvertently shut-in.



In all these cases the quicker the HIPPS system reacts the shorter the fortified section can be. Likewise a quicker response time may allow operating closer to the MAOP of the protected flowline and riser. If the fluid upstream of the valve is incompressible a quick closure will generate a rapid pressure surge which must be evaluated to ensure it does not overpressure any of the upstream components.

1.3.4 TASK 400 – MATERIALS SELECTION

This section investigates materials issues with respect to HIPPS equipment. It summarizes the materials requirements of recently-released API RP 17O including how API RP 17O addresses materials issues, such as corrosion, temperature effects on materials, and SCC/SSC. Included with this discussion is a brief summary of how each of the specific material issues is currently addressed by industry for other subsea equipment. The conclusion reached is that there are no conditions warranting special regulatory guidance for HIPPS in regards to materials selection. The same design methods and materials used for other subsea oil field equipment such as trees can be applied to HIPPS.

1.3.5 TASK 500 – LENGTH OF FORTIFIED SECTION REQUIREMENTS

The intent of this section is to review the issues associated with the fortified flowline segment downstream of the HIPPS.

The length of the fortified section should be determined based on flow analysis assuming flow is blocked at some point downstream. Chemical prevention of blockages in the flowline can not be relied on to prevent blockages from happening. It is conceivable that fortification may not be required, but this shall be proven based on flow analysis and comparison to code limitations.

Flow assurance considerations are discussed and an illustrative example presented to show how the fortified section is influenced by these factors. Factors such as the over pressure scenario, field architecture, product composition, and variations of production with time are discussed. Transient analysis is thus recommended.

Behavior of other HIPPS systems will vary from this example and will require corresponding analyses to assess the flow assurance.

1.3.6 TASK 600 – HIPPS FLOWLINE VERSUS RISER BURST IN DEEPWATER HIPPS

As an additional safety measure in the event of a HIPPS failure, the MMS currently mandates that a HIPPS protected riser be more resistant to burst than its corresponding protected pipeline. Current design codes for pipeline and riser systems capable of



withstanding full pressure call for a higher safety factor for the riser. The de facto result of these codes is that, in shallow and moderate water depth systems, should the system be over pressured, the pipeline would fail first meeting the MMS criteria. This limits consequences to economic and environmental damage rather than injury to personnel.

As water depths get deeper, however, the effect of external pressure becomes more pronounced. The pipeline must be strong enough to resist collapse due to external water pressure when empty. This can offset the relative difference in pipeline and riser code burst safety factors since the pipeline design is controlled by collapse rather than burst. In addition, for products less dense than seawater, before the pipeline can burst it must overcome the external water pressure. This effectively strengthens the pipe against burst. This is not the case at the top of the riser where there is no external water pressure. These factors require a corresponding increase in riser strength or fortification to prevent the riser from being the weakest point in the system.

Riser fortification will, under certain conditions, constrain the riser to be stronger than if the HIPPS is considered adequate to protect the riser and facilities. This may cause the riser wall thickness to increase to the point where pipe procurement, welding, and/or installation are difficult or impossible to accomplish. This study shows that this issue is most applicable at water depths in the 5,000 to 10,000 foot range and for larger pipe on the order of 14 to 22 inches in diameter.

Graphical tools presented in this section can be used to determine where these constraints are likely to affect the riser design.

This section also addresses the degree of riser fortification that would apply to various scenarios, depending on the amount of overpressure that could result in the event of a general system failure followed by a HIPPS failure. A factor consistent with the current strength ratio between flowlines and risers is suggested for the most severe cases with the degree of riser strength over that of the flowline decreasing as overpressure severity reduces.

1.3.7 TASK 700 – CODE REVIEW AND RECOMMENDATIONS ON REGULATION

This section provides a brief summary of API RP 17O and discusses how the normative references within apply to different parts of the HIPPS. The codes related to design of the safety instrumented systems (SIS), IEC 61508 and IEC 61511 are explored in more depth with guidance on their applicability to a subsea HIPPS. The section concludes with a discussion of pipeline codes and their relation to HIPPS.



Various equipment codes and standards are referenced by API RP 17O and apply to their corresponding areas as they do for a non-HIPPS design.

When using a HIPPS, API 1111 is recommended as the design code of choice for flowlines, risers or pipe in agreed flowline components such as jumpers or PLEMs. Recommended in order of applicability for subsea use for piping not part of a flowline segment is ASME B31.8 with ASME B31.3 reserved for those specific items not addressed adequately by B31.8.



2. TASK 200 – HIPPS VALVE LEAKAGE RATE REQUIREMENTS

2.1 Scope

This section addresses issues surrounding leakage of HIPPS valves. Specifically, the study discusses issues related to determination of a leakage rate across HIPPS valves by in-situ testing and the impact of such a leakage on a generic system.

2.1.1 Task Summary

The design of HIPPS systems assume that once the HIPPS valves are closed, no leakage can occur past the valves. If a leakage across the HIPPS valves is discovered after the system is in place, then the operator will need to obtain a deviation request from the MMS to continue operating with the non-compliant system.

As part of the deviation request, the operator will have to demonstrate that the system can continue to operate safely with the leaking HIPPS valves. Two different types of analyses need to be performed as part of the request. First, the rate and nature of the leakage has to be determined. These data can be determined through pressure testing and analysis. Second, the leakage information is fed into a separate analysis to determine the effects on the system as the leakage progresses. This analysis should demonstrate that within the defined parameters a leakage does not create a hazardous condition or violate any rules.

This section defines the relevant variables for the testing and analysis mentioned above. A general discussion of how testing and analysis should be performed is presented. To support these discussions and to illustrate some of the variables, a typical HIPPS manifold and flowline system are described including sketches. Sensitivity analyses are performed for leakage testing and flowline packing on a typical system to illustrate effects of relevant variables. The study concludes with bulleted lists of considerations that are important for evaluating general deviation requests related to leaking HIPPS valves.

2.1.2 Problem Statement

Most HIPPS system designs assume that the HIPPS valves are zero-leakage devices. That is, once the HIPPS valves are fully-closed it is assumed that they are bubble-tight and no fluids can cross the valve interface. This assumption allows flow assurance analysis of the HIPPS system to be constrained to a relatively short period during and after valve closure to capture dynamic effects. The inherent assumption is that once the flowline contents have settled out there will be no pressure fluctuations upstream or downstream of the HIPPS valves due to mass transfer across the HIPPS valves.



Testing is performed on the HIPPS valves to verify the zero-leakage requirement. Depending on the specification(s) controlling the testing process, HIPPS valves may undergo static and dynamic cycle testing, simulated-service flow loop testing, hyperbaric testing, hydrostatic and gas leak testing, and thermal testing. Valves used for HIPPS applications have to prove themselves to be leak-free under the worst-case combination of the prescribed tests. Under laboratory conditions, it is relatively easy to determine whether any leakage has occurred during testing. Valves can be monitored to detect any visible liquid or gas leakage. High-precision pressure and temperature gauges, relatively small test chamber volumes, and long hold times allow leakage to be determined through chart recordings. In short, it is quite feasible to prove that a HIPPS valve is leak-free prior to its being installed in the field.

Once installed and commissioned, a HIPPS system will require periodic testing. Part of this testing is leak testing across the HIPPS valves. Leak testing in-situ is much more challenging than that performed in a laboratory. Temperature and pressure gauges may be less precise than those used for surface testing. There will likely be a relatively large test chamber volume upstream of the HIPPS valves. Once shut in for testing, the flowline and its contents will cool to ambient temperatures, introducing a dynamic element. Long hold times may not be feasible due to commercial or flow assurance concerns. All of these variables make testing a HIPPS valve to ensure zero leakage a challenging prospect.

It is possible that with certain combinations of sensor precisions, test chamber volumes, fluid composition, temperature variations, hold times, etc., a leakage across a HIPPS valve may be present that can not be detected. This 'theoretical' leakage rate may be calculated by considering a worst-case combination of the relevant variables. This is not to say that there is an actual leak across the HIPPS valve being tested, but that there is the potential that an undetectable leak at some rate up to the theoretical maximum may be present despite a 'flat-line' pressure test. Should the pressure test show that an actual leakage across a HIPPS valve is present this rate can be calculated using data from the relevant variables. However, similar to the results for a zero-leakage pressure test, it is possible that the actual leakage rate is higher (or lower) than that calculated using test data without considering data variability.

So it is possible that an installed HIPPS valve may demonstrate zero leakage during periodic testing and still have a non-zero leakage rate. Likewise, it is also possible that a HIPPS valve that demonstrates a calculable leakage rate may actually have a higher leakage rate when sensitivities are considered. Thus the assumption of zero mass transfer across the HIPPS valves typically used in HIPPS system analysis may not be valid for certain cases. If a leakage occurs across the HIPPS valves, it can reasonably be



assumed that pressure downstream of the HIPPS valves will rise at a certain rate from the 'static' pressure calculated assuming zero valve leakage. This pressure increase may affect a non-fortified section of flowline depending on location of blockages downstream of the HIPPS valves. Given enough time and assuming that there is sufficient potential energy upstream of the HIPPS valves, a portion of the non-fortified flowline may experience a pressure above its MAOP.

This section will examine two separate but related issues:

1. What needs to be considered to determine a maximum theoretical leakage rate across HIPPS valves for in-situ leak testing;
2. What needs to be considered to determine the impact of a given leakage rate across HIPPS valves on the downstream flowline system.

The intent of the above discussions is to present a picture of the issues associated with determining a potential leakage rate across HIPPS valves and the resulting impact to the flowline system to provide guidance in evaluating deviation requests relative to HIPPS valve leakage.

2.2 HIPPS Valve Leakage

2.2.1 Definition of Zero-Leakage

A HIPPS valve is considered to be zero-leakage if there is zero mass transfer while a pressure differential exists across the valve's sealing element. Using mass transfer as the basis for defining leakage is more general than using change in pressure on the upstream or downstream sides of the valve. For instance, if there is a non-depleting pressure source on the upstream of the valve, say an open well, then a relatively small leak can exist across the valve with no noticeable drop in pressure upstream even for indefinite hold times.

However, as a practical matter, the mass transfer definition of leakage is not useful for determining if a HIPPS valve is leak-free. Subsea flow meters are not designed to measure flow rates that would result from relatively small leaks. Also, direct observation of leakage is not possible subsea, as it would be in laboratory testing.

So the only practical way to determine leakage across a HIPPS valve subsea is by monitoring pressure change during testing. As the example above illustrates, leakage testing by monitoring pressure change can be misleading if everything affecting the pressure being monitored is not considered/controlled. This is discussed further below.



2.2.2 Description of Subsea Leak Testing

Figure 2-1 depicts one possible arrangement of valves and test sensors for a HIPPS system. This manifold arrangement includes dual HIPPS valves, dual bypass valves, and a test valve. Other arrangements may vary significantly from the one shown. For instance, a dedicated test valve may not be included, instead relying on other valving upstream to isolate a test chamber. However, this arrangement is suitable for demonstrating a general procedure for HIPPS valves leak testing.

In this example a single combined PT (pressure/temperature) sensor has been located to monitor pressure and temperature within the test chamber. Actual arrangements may consist of separate sensors for pressure and temperature with added units for redundancy.

The direction of flow is indicated with the pressure source (open well or subsea pump, for instance) located upstream of the HIPPS arrangement.

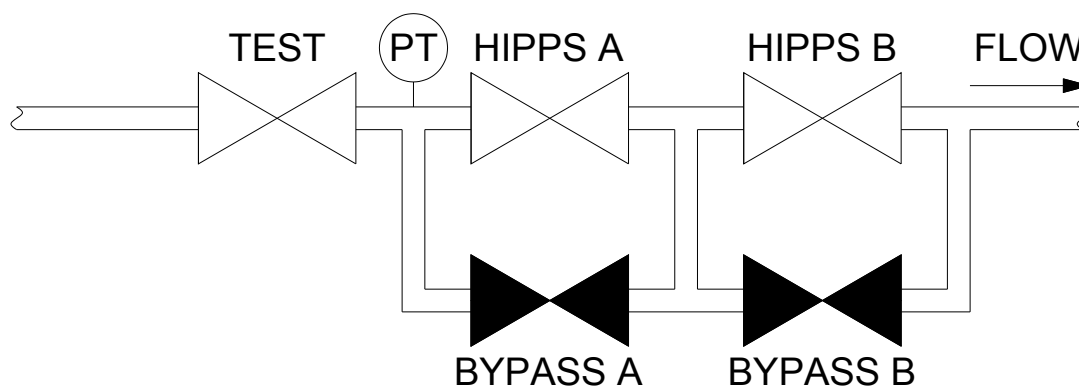


Figure 2-1 Typical HIPPS Valve Arrangement

Figure 2-2 depicts a leakage test being performed on the upstream HIPPS valve, HIPPS A. The Test, HIPPS A, and Bypass A valves are closed. HIPPS B and Bypass B are open to provide a leak path downstream. The test chamber consists of the shaded volume shown in the figure. Pressure is raised in the test chamber to that required by the test. One way of achieving this is to provide an injection point in the manifold for, say, methanol. Starting and ending pressures and temperatures are read by the PT sensor. Figure 2-3 shows the corresponding arrangement for testing HIPPS B.

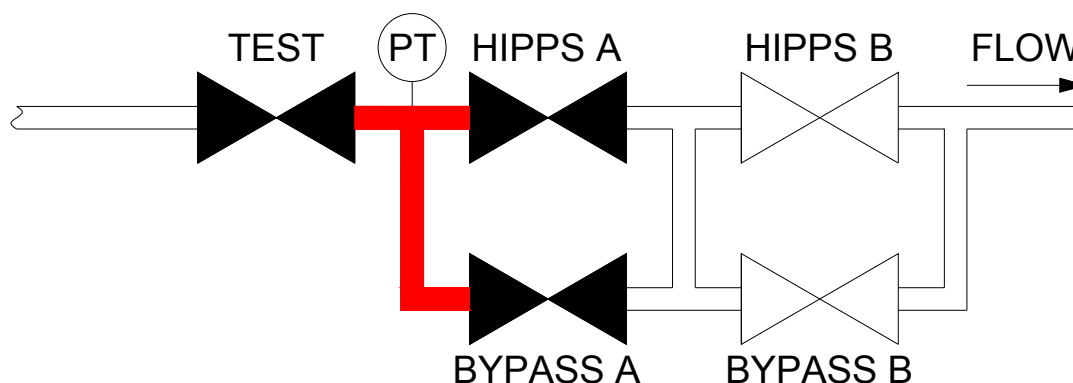


Figure 2-2 Leakage Test of HIPPS A Valve

Figure 2-3 depicts the valve arrangement for leak testing the HIPPS B valve.

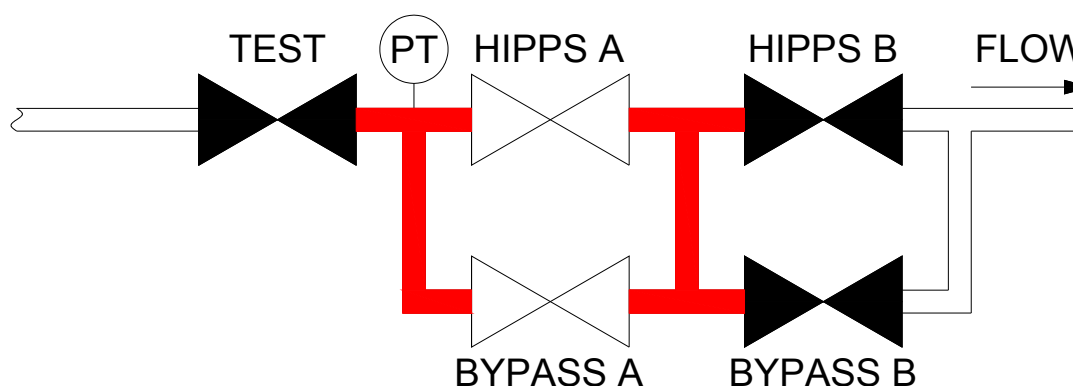


Figure 2-3 Leakage Test of HIPPS B Valve

2.2.3 Variables Affecting Determination of Leakage Rate

2.2.3.1 Hold Time

Hold time is the period that pressure drop is monitored and recorded to determine whether leakage is occurring across a HIPPS valve. Short hold times are desirable for two major reasons. First, for HIPPS systems involving untreated well fluids, there may be a risk of hydrate formation during shut-in periods. Short hold times minimize the heat loss and temperature drop from these systems and allow restart sooner. Second, long hold times are undesirable from a commercial standpoint. For flowline systems, there is the obvious deferment of production while the system is shut in for testing. For export systems, say a gas export line with a HIPPS system, multiple fields could be shut in until testing is complete.



Hold time is an important variable for leakage testing and is related to most of the other testing variables. While short hold times may be desirable for reasons not related to leakage testing, longer hold times may be necessary to get a good test. Discussion of the impact of hold time on each relevant testing variable is contained within the sections below.

2.2.3.2 Test Chamber Volume/Isolation

The test chamber is defined as the enclosed volume that is being monitored for a change in pressure. All else being equal, a larger test chamber has a smaller pressure drop for a given mass transfer. Smaller test chambers have more pressure change sensitivity than larger ones.

Test chambers should be isolated from energy sources such as open wells, subsea pumps, flowline-heating systems, etc. These energy sources introduce dynamic variables to leakage testing that can not be quantified or accounted for.

In general, larger test chambers require longer hold times. This is because a larger test chamber requires that more fluid leak from the chamber to register a known pressure drop than from a smaller chamber. If the leakage rate is the same between the larger and smaller chambers then obviously more time is needed for the larger chamber to register the known pressure drop.

2.2.3.3 Temperature Change

The absolute temperature of fluid within the test chamber and the test chamber itself is relatively unimportant for subsea valve testing. However, if this temperature changes significantly during testing then pressure changes within the test chamber will be recorded. If temperature is not recorded and accounted for during a test then these pressure changes may be misinterpreted as leakage.

The impact of temperature change on a leak test depends on the particulars of the HIPPS system design. For a test chamber containing liquids that is well-insulated, the rate of heat loss, and the corresponding temperature drop, may be relatively low. However, for a gas system with uninsulated equipment the opposite may be true. Either way, temperature must be measured and accounted for during leak testing to account for its effects on pressure change.

Temperature is related to hold time in that longer hold times generally result in larger temperature changes. This is especially true for flowline systems where the produced fluid may have a high differential temperature relative to the ambient seawater. Longer hold times and associated higher temperature changes are not necessarily negative for



leakage testing as calculations have to consider even small temperature changes to determine whether a pressure change during testing is the result of temperature or an actual leak.

If testing is done with methanol or other fluid that has reached ambient temperature prior to being introduced for the test, for example due to residence time in an umbilical, temperature effects can be minimized.

2.2.3.4 Sensor Properties

Two different sensor types are required for HIPPS valve leakage testing: pressure and temperature. Although they obviously have different functions, the properties affecting the two sensor types are similar and will be discussed generally.

Sensor accuracy may be important for some leakage calculations where absolute values are required for calculations. Equations of state for gases are an example. Sensor drift may have some impact on these calculations over months or years and should be considered. Sensor drift is probably not important for the actual period of the leak test considering the relatively short hold periods associated with leak testing.

The absolute precision of a typical sensor is limited by digitizing the signal from the analog signal. This limitation on absolute sensor precision is important, but looking at the precision of the sensor alone can be non-conservative. Given a constant pressure or temperature and taking numerous readings of the sensor, there will be some range of the readings around the nominal value. This sensor randomness may be the result of influences separate from the sensor itself and may thus exceed the range of stated sensor precision. Therefore it is important to characterize sensor precision in the actual environment (or an equivalent simulated environment) where readings will be taken.

2.2.3.5 Fluid Properties

The test chamber may contain a mixture of fluids. Liquids may comprise crude oil, produced water, hydrate inhibitors, or other compounds. Similarly, gases may be comprised of a variety of compounds, although the gas phase is typically not as variable as the liquid phase. Liquid and gas phases may both be present in some range from pure liquid to pure gas. This proportion of gas to liquid in various sections of a flowline will vary depending on how gases and liquids settle out after a shut-in for that particular system. It is important to note that the liquid/gas mix of produced fluid varies throughout the life of a well.

Consideration of the fluid properties is important for two reasons. The first reason is determination of the effect of temperature on pressure within the test chamber. Enclosed



liquids and enclosed gases will respond differently to a change in temperature. Second is determination of a leakage rate across the valve should a leak exist. The volume of pure liquid leaked giving rise to a determined pressure drop is quite different from that of pure gas. Analysis can be further complicated if the contents of the test chamber can cross a phase boundary between liquid and gas as temperature and pressure change.

2.2.4 Determination of Leakage Rate

All variables listed in Section 2.2.3 need to be considered when determining if a leakage across the HIPPS valves exists, and if so the rate of the leak.

The hold time should be long enough to allow a leak to reveal itself should one exist. A larger test chamber volume will require a longer hold time to allow a significant amount of fluid to leak allowing the pressure sensors to register a pressure drop.

If a multiphase mixture exists within the test chamber, it may not be determinable as to whether a liquid or gas is leaking across the HIPPS valves. In this case, the conservative approach is to assume the leak consists of pure gas or pure liquid, whichever is worse for the particular system. The composition of the fluid within the test chamber may change as a test progresses due to differential leakage of liquids and gases across the HIPPS valves and/or phase changes of the fluid due to changes in pressure or temperature.

Temperature of the test chamber should be measured both at the beginning of the hold period and at the end. These temperatures may be used to account for pressure drop attributable to the fluid temperature cooling to ambient. The temperature gauge(s) will have a certain amount of randomness while taking multiple readings. To reduce and/or characterize this randomness, multiple readings should be taken at the beginning and end of the hold time. Statistically processing these multiple readings will allow determination of average starting and ending temperatures with a calculable standard deviation. Thus, using the average temperatures and their standard deviations, it is possible to determine worst-case starting and ending temperatures to a certain confidence level. The conservative approach to accounting for the effects of temperature on pressure changes in the test chamber is to minimize the temperature drop by using the starting temperature at its low value and the ending temperature at its high value. In circumstances where these values overlap, the effects of temperature may not apply for the particular test.

Pressure in the test chamber should be measured both at the beginning of the hold period and at the end. The pressure gauge(s) will have a certain amount of randomness while taking multiple readings. To reduce and/or characterize this randomness, multiple readings should be taken at the beginning and end of the hold time. Statistically processing these multiple readings will allow determination of average starting and ending



pressures with a calculable standard deviation. Thus, using the average pressures and their standard deviations, it is possible to determine worst-case starting and ending pressures to a certain confidence level. The conservative approach is to maximize the pressure drop by using the starting pressure at its high value and the ending pressure at its low value.

The first task is to determine whether a leak is actually present across the HIPPS valves. Given a defined test chamber volume, fluid composition, temperature change, and starting pressure, an analysis can predict what final pressure should exist in the test chamber after accounting for pressure changes due to temperature change and any possible changes in fluid properties. This value can be compared to the actual ending pressure and if the ending pressure from the actual test is significantly lower than that calculated, it can be inferred that a leak exists. The analysis should consider statistical variation of temperature and pressure readings and should address uncertainty of the fluid composition. Using only average pressure and temperature readings in the analysis may result in a small but significant leakage going undetected.

If the first analysis demonstrates that a leakage across the HIPPS valves is present, then a second analysis should be performed to determine the magnitude of the leak. Even if the contents of the test chamber are known with certainty, a leakage rate should be calculated for both pure liquid and pure gas. Even if the test chamber contents are known, the fluid leaked during an actual HIPPS activation scenario may differ from that leaked during the test. This analysis will be similar to the above in that all relevant variables should be considered, but is varied by allowing a certain rate of liquid oil or gas to escape the test chamber until the final analysis pressure matches that found during leak testing. Once again, statistical variations should be considered to determine a worst-case leakage rate.

The specifics of how these analyses will be performed will vary from case to case. What is important is that all variables and their uncertainty be considered and addressed. If an analysis involves phase changes or other non-linear phenomena, the analysis should address these non-linearities.

2.3 Impact of HIPPS Valve Leakage

2.3.1 Description of Typical HIPPS Flowline System

Figure 2-4 depicts a simplified, typical HIPPS flowline system. Actual systems will be highly variable and will almost certainly be more complicated than depicted. However, this schematic is useful for general discussion.



The pressure source may be a subsea pump, an open well, or some other source. In this example, the pressure source is isolated by an upstream valve, which could be a USV on a tree or a flowline isolation valve on a manifold. Further downstream are the HIPPS valves, which here are shown on a separate manifold, although this arrangement can vary. Next in the flow stream is the downstream valve/blockage. The location and nature of this element will vary based on the specifics of the system being investigated. For instance, the downstream valve/blockage may be a boarding valve on a platform or it may be a hydrate plug that has formed somewhere in the flowline.

The upstream volume for this example is that between the upstream valve and the HIPPS valves. Similarly, the downstream volume is between the HIPPS valves and the downstream valve/blockage. These volumes are used in the analysis discussed below.

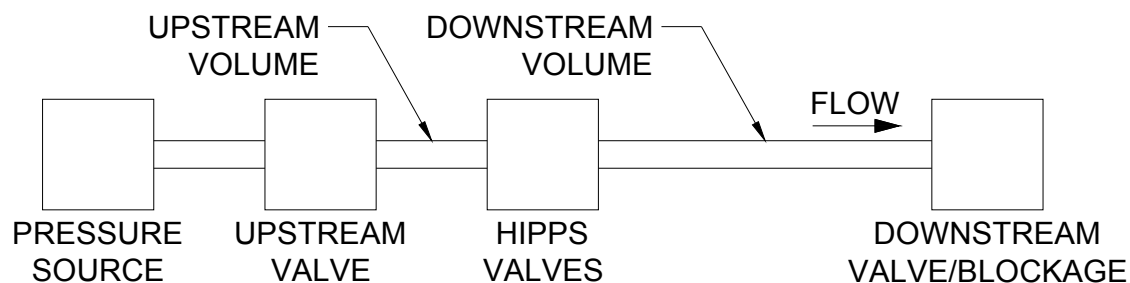


Figure 2-4 Typical HIPPS Flowline Schematic

2.3.2 Variables Affecting Impact of HIPPS Valve Leakage on Flowline System

2.3.2.1 Leakage Rate

The leakage rate as determined in Section 2.2.4 is used for determining the impact of a HIPPS valve leak after activation of a HIPPS system. The leakage rate used may be either the nominal leakage rate or a worst-case rate that factors in sensor inaccuracies.

Depending on the system, pure liquid, pure gas, or a combined multiphase fluid may leak across the valve. The composition of the fluid leaked across the HIPPS valves should be described in concert with the associated leakage rate.

2.3.2.2 Volume Upstream of HIPPS Valves

The volume enclosed upstream of the HIPPS valves is related to the energy available to drive a leak. The larger the volume, the more fluid is available to leak across the HIPPS valves. As a leak progresses, pressure depletion in a larger volume occurs more slowly than in a relatively small volume.



2.3.2.3 Composition of Fluid Upstream of HIPPS Valves

The composition of the fluid available to leak across the HIPPS valves needs to be characterized. Liquids leaking across the HIPPS valves will have different effects than gases. The fluid composition is not necessarily constant over time. For instance in a multiphase flowline with a subsea HIPPS the HIPPS valves may be in a low spot of the flowline with liquid accumulated against the closed HIPPS valves. As this liquid is leaked, it may be replaced by a multiphase fluid or pure gas. Also, as pressure drops or temperatures lower towards ambient, there may be a phase change with liquids flashing to gas.

The composition of produced fluids may vary significantly throughout the life of a well in regards to both gas/liquid ratio and components of the gases and liquids. For instance, a well may experience significant water breakout late in life necessitating increased lift gas to produce the well. The fluid properties used for analysis should be worst-case for the period during which the HIPPS is required.

2.3.2.4 Mass/Energy Transfer into Volume Upstream of HIPPS Valves

In most cases, the enclosed volume upstream of the closed HIPPS valves will be isolated from any energy sources such as subsea pumps or open wells. In the event of HIPPS activation the likely scenario is that pumps would be shut off and wells would be shut in. However, there is always a possibility that interlocks will fail and as an example pumps would continue to operate and deadhead against the HIPPS valves. Another possibility is that the USV valve(s) on a subsea tree are themselves leaking and introducing fluids into the upstream volume. SCSSVs and USVs are allowed to leak at a rate of 400 cc/minute or 15 scf/minute, so this should be accounted for as a minimum. Other sources of energy or mass transfer into the volume upstream of the HIPPS valves are possible and need to be characterized.

2.3.2.5 Volume Downstream of HIPPS Valves

This variable is similar to that described in Section 2.3.2.2. For a smaller downstream volume, less fluid may leak across the HIPPS valves since as a leak progresses, pressure rise in a smaller downstream volume occurs more swiftly than in a relatively large volume.

2.3.2.6 Composition of Fluid Downstream of HIPPS Valves

This variable is similar to that described in Section 2.3.2.3. The starting composition of the downstream fluids may change as a leak progresses due to both the composition of the fluid being leaked and potential phase changes with changes in pressure and temperature.



2.3.2.7 Mass/Energy Transfer from/into Volume Downstream of HIPPS Valves

This variable is similar to that described in Section 2.3.2.4. There may be some removal of fluid from the downstream volume through a relief valve or some other arrangement. However, there is also the possibility the opposite is true and that fluid is being introduced into the downstream volume from some source other than the leak across the HIPPS valves. This may be from a tie-in from another field, for instance. Also, as an example, energy transfer into the downstream volume could be from compressors in a tee-in branch of a gas export system. Some of these scenarios may not be too likely to occur, but all possibilities should be considered.

2.3.2.8 Time of Leakage across HIPPS Valves

The total time that a leak occurs after the HIPPS valves are activated is system dependent and may not be readily determinable for all scenarios. The worst case scenario is that a catastrophic event occurs and intervention can not be undertaken for an indefinite period. As an extreme example, the volume downstream of the HIPPS valves may consist of a flowline terminating at a closed subsea isolation valve. If the flowline/riser downstream of the isolation valve is lost due to say an anchor snag or platform loss, then intervention to the flowline might be impossible for months or even years. A leakage event occurring over months or years may be much more consequential than one lasting days or weeks.

2.3.2.9 System Pressures at Beginning of Leakage

In a flowing system, there is a certain flowing pressure distribution along the flowline. As an event occurs that raises pressures sufficiently to activate closure of the HIPPS valves, say an unexpected closing of a boarding valve, these flowing pressures will change throughout the system. After the HIPPS valves are fully closed and a certain time elapses, pressures will stabilize both upstream and downstream of the HIPPS valves. These pressures may be as high as a shut-in/deadhead pressure upstream of the HIPPS valves and as high as the MAOP of the unreinforced flowline section downstream, depending on specifics of the system design and conditions before and during the HIPPS activation. In general, the pressure upstream of the HIPPS valves will be higher than that downstream.

2.3.2.10 Temperature

For most systems the likely scenario is that the system would be shut in after HIPPS valve activation and the system would cool to ambient temperatures. However, some systems may have the potential for sections of the system to change temperature during a shut-in



scenario, say through a flowline heating system. If so, the effects of global or local temperature changes should be considered.

2.3.3 Determination of Impact of HIPPS Valve Leakage

Leakage rate across the HIPPS valves as determined in Section 2.2.4 is a primary variable for determining what impact a leakage has on the system downstream of the HIPPS valves. Also important is the composition of the fluid that is leaking at the calculated rate. This composition may change as a leak progresses due to phase changes or depletion of one phase allowing another to leak in its place. For instance, a pool of liquid against the HIPPS valves may deplete sufficiently for gas to 'break through' and leak in concert with the liquid or replace it entirely. The analysis should consider what is worst-case for the particular system.

Volume and fluid composition of the enclosed volumes upstream and downstream of the HIPPS valves are used in analysis to determine the effects of leakage on pressure change. For instance, gas leaking into a liquid filled line will be quite different from an instance where liquid leaks into a gas filled line. The fluid compositions are system and condition dependent.

For systems where there is energy or mass transfer into or from the volumes upstream and downstream of the HIPPS valves, these variables should be considered if relevant over the period of leakage. For instance, if a production well is not shut in for a production system then there is no depletion of pressure or fluid upstream as a leak progresses. As another example, the downstream flowline may be equipped with a relief valve topsides. Consideration of the relief valve capacity and any failure scenarios would then need to be part of the leak evaluation.

For systems where temperature may vary during the leakage, this temperature change should be included as part of the calculation.

The initial pressure distribution should be found to establish starting conditions. If the volume downstream of the HIPPS valves is at or close to the MAOP of the unreinforced flowline section, then no or very little leakage may be tolerated. If the pressure upstream of the HIPPS valves is close to that downstream, then a small amount of leakage may balance pressure between the two sides and the leak will stop. This assumes of course that there is no energy or mass transfer into the upstream volume, as described above.

The time period over which a leak occurs depends on the particulars of the scenario that caused activation of the HIPPS valves. In extreme cases, it may not be possible to



intervene for months or years. It is conservative to assume that a leakage will occur until an equilibrium is established and the leak stops or until there is a system failure.

Determining the impact of leakage across the HIPPS valves is essentially a non-linear problem. The analysis will become more complicated the more the conditions move away from being static. The analysis is basically a flowline packing analysis modified to account for the particularities of a relatively low flow rate, that of the leak across the HIPPS valves. Any such analysis will depend strongly on the starting variables and on any changes to the system as the leakage event occurs, such as activation of pumps or a flowline heating system. This analysis will be highly system dependent.

2.4 Sensitivity Analysis

A series of sensitivity analyses were performed for both HIPPS valves leakage testing and for effects of HIPPS valve leakage on the downstream flowline (flowline packing). These analyses were performed to illustrate in a relative way how the variables in Section 2.2.3 for HIPPS valve leakage testing and Section 2.3.2 for flowline packing affect leakage testing and flowline packing.

Note that the conclusions based on analysis performed in this section may or may not be valid if applied to other systems. The sensitivity analysis is performed to highlight broad trends of different variables and the results should be applied with caution to real world systems.

2.4.1 Methodology

Analysis was performed using the Olga multiphase flow software. A full multiphase analysis was performed to capture any transient effects in the analyses such as gas flashing or condensing. A black oil model with methane gas was used as a typical product for all analyses. The bubble point of this fluid is around 6200 psia.

For both types of analysis, a constant leak rate of 15 scf/min of gas was used. For the GORs considered, the gas leakage rate was controlling rather than the potential liquid leakage rate of 400 cc/min. This is beneficial in that all of the analysis performed is directly comparable for sensitivities since there are no step changes between analyses due to different leakage rates.

The 15 scf/min leakage rate was achieved in the analyses by imposing a controlled mass transfer across the barriers (HIPPS valves). This analysis method was chosen over modeling a fixed orifice with an initial 15 scf/min leakage rate since there is no change in the leakage rate as the analysis proceeds. This is acceptable for this sort of sensitivity analysis since leakage rate is not a variable. The leakage and packing times shown in the



sections below would likely be longer in a real world situation since the leakage rate across a fixed orifice will decrease as the pressure differential decreases.

For the leakage analysis, it was assumed that there was no mass transfer into the test chamber from an upstream source (pumps or an open well, for instance). This is reasonable for a sensitivity analysis, although leakage into the test chamber needs to be considered for real world analysis. The fluid from the test chamber is assumed to leak across the HIPPS valves into a gas-filled 5000 psi flowline with no packing effect. For the packing analysis, it is assumed that there is a constant supply of 15000 psi fluid upstream of the HIPPS valves. Thus, any leak across the HIPPS valves would continue until the downstream section reaches 15000 psi. This assumption simulates the effect of leaking USV and SCSSV valves of an upstream tree.

Two temperatures for the leakage test were considered. Ideally, before leakage testing begins, the test chamber temperature would be stabilized at ambient conditions to reduce the impact of temperature change on the test. However, for economic or flow assurance reasons, the test may be performed soon after shut in with an elevated temperature fluid. This elevated temperature fluid was considered to find its effect on the leakage test. For the packing analysis, only ambient temperature was considered. This is because flowline packing in a real world case will be of considerable duration relative to leakage testing and the system will have time to cool to ambient temperature.

The GOR of the fluid for both types of analyses stays constant for any particular analysis. In a real world case, there may be some differential leakage across the HIPPS valves. That is, leakage may be all fluid, all gas, or some combination with an equivalent GOR different from that of the overall fluid. Considering varying GOR in a particular analysis is not useful for a sensitivity analysis and is thus excluded.

2.4.2 HIPPS Valve Testing Analysis

Four variables were considered for the valve testing leakage sensitivity analyses: test fluid temperature, initial test chamber pressure, test chamber volume, and test fluid GOR. Different combinations of these variables were analyzed given a set gas leakage rate of 15 scf/min. The time required for the initial pressure to drop 1000 psi was found for each case.

Two temperatures were considered: 40°F and 200°F. These represent deep sea ambient temperature and a reasonably high flowing temperature, respectively.

Two test chamber initial pressures were considered: 10000 psi and 15000 psi. These pressures are considered typical for flowline HIPPS. Note that pressure downstream of



the test chamber was not part of the problem definition. This is due to the definition of a set gas leakage rate rather than definition of an orifice size and differential pressure. It is possible that a specific leakage analysis may use the orifice and differential pressure methodology rather than the set leakage rate. Doing so will result in a varying leakage rate as pressure in the test chamber is reduced. It is likely that a downstream pressure close to the test chamber pressure will result in a reduced leakage rate. An increased delta pressure across the orifice will likely result in an increased leakage rate.

Two test chamber volumes were considered: 10 ft³ and 50 ft³. These numbers cover a reasonable test chamber volume range up to the maximum allowable volume previously cited by the MMS.

Three GORs are considered: 1500, 3000, and 4500 scf/stb. This range is considered typical for produced fluids in the Gulf of Mexico.

Table 2-1 lists the results of the analyses performed considering the variables listed above. Results are listed in seconds.



Table 2-1 HIPPS Valve Testing Analysis Results

| Fluid Temperature | Initial Test Chamber Pressure | Pressure Drop | Test Chamber Volume | Time (s) | | |
|-------------------|-------------------------------|---------------|---------------------|---------------|------|------|
| (°F) | (psia) | (psi) | (ft³) | GOR (scf/stb) | | |
| | | | | 1500 | 3000 | 4500 |
| 40 | 10000 | 1000 | 10 | 45 | 107 | 157 |
| | | | 50 | 224 | 528 | 776 |
| | 15000 | | 10 | 31 | 70 | 100 |
| | | | 50 | 152 | 344 | 495 |
| 200 | 10000 | | 10 | 77 | 177 | 252 |
| | | | 50 | 379 | 867 | 1246 |
| | 15000 | | 10 | 49 | 107 | 151 |
| | | | 50 | 240 | 528 | 747 |

Some observations can be made from these results:

- The leakage time increases linearly with the test chamber volume. This linearity arises since there is no flashing of gas within the test chamber since the minimum pressure achieved (9000 psia) is above the bubble point;
- Higher initial test chamber pressure results in shorter leakage times. This is explained by the denser fluid in the higher pressure chamber relative to that in the lower pressure chamber being removed at a constant volumetric rate;
- Higher fluid temperature results in longer leakage times. This is explained by the less dense fluid in the higher temperature chamber relative to that in the lower temperature chamber being removed at a constant volumetric rate; and
- Higher GOR fluids have longer leakage times. This is because the leakage rate is gas limited and the higher GOR fluids have a smaller amount of liquid removed



from the chamber per unit volume of gas. A lower rate of liquid removal results in slower pressure drop times.

The worst combination of variables for valve leakage testing is that which maximizes the time required for pressure to drop a given amount. This is because a short hold period given the worst combination of variables may not be long enough to exhibit a significant pressure drop given the errors and randomness associated with pressure transducers. **Thus, it is recommended that more attention be given to HIPPS valve leakage test calculations involving higher temperatures, lower test chamber pressures, higher test chamber volumes, and higher test fluid GORs.** This combination of variables will lead to longer leakage times and poorer leak detection.

2.4.3 Flowline Packing Analysis

Three variables were considered for the flowline packing sensitivity analyses: initial downstream pressure, downstream flowline length, and produced fluid GOR. Different combinations of these variables were analyzed given a set gas leakage rate of 15 scf/min. The time required for the initial downstream pressure to rise 1000 psi was found for each case.

Three initial downstream pressures were considered: 5000, 8000, and 10000 psi. These pressures are considered typical for flowline HIPPS. Note that pressure upstream of the HIPPS valves was not part of the problem definition. This is due to the definition of a set gas leakage rate rather than definition of an orifice size and differential pressure. It is possible that a specific packing analysis may use the orifice and differential pressure methodology rather than the set leakage rate. Doing so will result in a varying leakage rate as differential pressure across the HIPPS valves varies. It is likely that a downstream pressure close to the pressure upstream of the HIPPS valves will result in a reduced leakage rate. An increased delta pressure across the HIPPS valves will likely result in an increased leakage rate.

Three downstream flowline lengths were considered: 500, 1000, and 2000 m. These numbers represent a reasonable range of fortified section lengths. The pipe over these lengths is assumed to have a 6 inch internal diameter.

Three GORs are considered: 1500, 3000, and 4500 scf/stb. This range is considered typical for produced fluids in the Gulf of Mexico.

Table 2-2 lists the results of the analyses performed considering the variables listed above. Results are listed in minutes.



Table 2-2 Flowline Packing Analysis Results

| Fluid Temperature | Initial Downstream Pressure | Pressure Rise | Downstream Flowline Length | Time (min) | | |
|-------------------|-----------------------------|---------------|----------------------------|---------------|------|------|
| (°F) | (psia) | (psi) | (m) | GOR (scf/stb) | | |
| | | | | 1500 | 3000 | 4500 |
| 40 | 5000 | 1000 | 500 | 34 | 142 | 271 |
| | | | 1000 | 75 | 284 | 541 |
| | | | 2000 | 150 | 569 | 1083 |
| | 8000 | | 500 | 27 | 65 | 96 |
| | | | 1000 | 54 | 130 | 192 |
| | | | 2000 | 109 | 261 | 385 |
| | 10000 | | 500 | 22 | 52 | 76 |
| | | | 1000 | 45 | 104 | 152 |
| | | | 2000 | 89 | 207 | 303 |

Some observations can be made from these results:

- The packing time increases roughly linearly with the downstream flowline length. Note that there is a small non-linearity for the highlighted section. This can be explained by gas flashing due to the downstream pressure being below the production fluid bubble point. However, this non-linearity is relative small in this case;
- Higher initial downstream pressure results in shorter packing times. This is explained by the denser fluid in the higher pressure flowline relative to that in the lower pressure flowline being added at a constant volumetric rate; and
- Higher GOR fluids have longer packing times. This is because the packing rate is gas limited and the higher GOR fluids have a smaller amount of liquid added to the



flowline per unit volume of gas. A lower rate of liquid addition results in slower pressure rise times.

The worst combination of variables for flowline packing is that which minimizes the time required for pressure to rise a given amount. **Thus, it is recommended that more attention be given to flowline packing calculations involving higher initial downstream pressures, lower downstream flowline lengths, and lower production fluid GORs.** This combination of variables will lead to shorter packing times.

2.5 Discussion of Regulatory Guidance

The preceding discussions of HIPPS valve leakage testing and determination of the effects of such a leak on a system apply to a HIPPS system that is not in compliance with its original specifications. HIPPS valves should be designed and qualified to be leakage-free. A HIPPS system that proves to have a leakage is thus likely not in compliance with the approved proposal to the MMS that allowed implementation of the system. Therefore, if a HIPPS system develops a leak, a deviation request will have to be presented by the operator to the MMS for approval to continue operating the system in its non-compliant state.

The sections below highlight some considerations that the MMS may consider to evaluate a deviation request related to a HIPPS valve leakage. These considerations are general and should apply to all deviation requests.

2.5.1 HIPPS Valve Leakage

- The analysis should demonstrate that the hold time of a leakage test is sufficient to demonstrate that a leakage is not present across the HIPPS valves. Reference Section 2.4 for typical sensitivity analysis;
- If the volume of the test chamber varies significantly due to pressure or temperature the analysis should capture this effect;
- The operator should demonstrate that the test chamber is isolated from external energy sources and from mass transfer into the chamber from a pressure source;
- The volume of the test chamber should be small enough to demonstrate leakage over the hold period should a leak be present. Reference Section 2.4 for typical sensitivity analysis;



- The temperature of the fluid in the test chamber should be recorded at the beginning and end of the hold period with enough readings sufficient to statistically define the temperatures;
- The pressure in the test chamber should be recorded at the beginning and end of the hold period with enough readings sufficient to statistically define the pressures;
- The analysis should use worst-case pressure and temperature values. The operator should define what values are worst-case considering statistical variation and confidence levels of the raw data;
- The operator should define the composition and properties of the fluid within the test chamber. If such a definition is not possible, then a worst-case composition should be assumed for analysis;
- Phase change of the test fluid should be considered if relevant;
- The operator should present an analysis methodology that considers all relevant variables. If a variable is not part of the leak analysis, then its exclusion should be justified;
- If a leakage is demonstrated, a worst-case leakage rate should be calculated for the defined composition of the leaking fluid;
- Leakage rates for pure liquid and pure gas should also be determined to account for variations in fluid properties over the system life and/or over the time frame of a leak;
- If a HIPPS system incorporates bypass valves in its design, these should be tested to the same standards as the primary HIPPS valves; and
- More attention should be given to HIPPS valve leakage test calculations involving higher temperatures, lower test chamber pressures, higher test chamber volumes, and higher test fluid GORs.

2.5.2 Impact of HIPPS Valve Leakage

- Use a worst-case leak rate determined from the leakage analysis;
- If the composition of the leaking fluid is not known, then use a worst-case assumption of composition and the associated leakage rate;



- Use the worst-case volume upstream of the HIPPS valves. The definition of this volume should consider the possibility of different valve openings/closings or any other configuration change that may occur during the leakage event;
- The worst-case volume downstream of the HIPPS valves should be used. The definition of this volume should consider the possibility of different valve openings/closings or any other configuration change that may occur during the leakage event and potential blockage locations due to hydrates, for example;
- Worst-case fluid compositions upstream and downstream of the HIPPS valves should be determined. Variations of the fluid compositions during field life and during a leakage event should be considered;
- The operator should consider mass transfer (other than across the leaking HIPPS valves) or addition of energy to the upstream volume for the leakage event due to a leaking USV or a flowline heating system, for example. If such conditions exist, they should be quantified and considered in the analysis;
- System pressures should be defined at the start of the leakage event by a worst-case dynamic modeling of the system;
- Temperature changes due to ambient cooling and any other sources should be defined over the period of the leakage;
- If the volumes upstream and downstream of the HIPPS valves varies significantly due to pressure or temperature (Poisson's ratio effects or thermal expansion) the analysis should capture this effect;
- The analysis should use a worst-case time period for the leakage analysis. If the operator can not sufficiently justify a shorter time frame, then a leakage event should be assumed to occur indefinitely;
- The analysis performed should be system specific and consider all of the defined variables. If a variable is not considered, its exclusion should be justified;
- Any possible modifications or alterations to the system should be considered. For instance, if another well is tied into the system its inclusion will alter starting variables for the analysis due the differing flow rated, fluid compositions, etc.; and
- More attention should be given to flowline packing calculations involving higher initial downstream pressures, lower downstream flowline lengths, and lower production fluid GORs.



3. TASK 300 – HIPPS VALVE RESPONSE TIME REQUIREMENTS

3.1 Purpose

The intent of this task is to present a thorough review of the issues associated with HIPPS valve response time and the resulting impact to the flowline system.

3.2 Problem Statement

For any HIPPS, the valve closure time is usually the dominant element of the overall system response time. The autonomous logic controller should trip quickly on reaching the 'High-High' activation pressure. The HIPPS System is designed in such a way that the system response, from the time the pressure trips the system to the time the HIPPS valves are shutoff, is kept to the minimum range.

There are three interrelated variables that operators will be required to determine and submit as part of their application for approval – the system closure time, High-High trip point and the length of the fortified section.

The valve response time varies from the type of valve, bore size, water depth, bore pressure, orientation, actuator hydraulic vent, size, and the design. The MMS requires that only positive closing (e.g. spring return) valves be in HIPPS for the GoM.

Another key task is determining the High-High trip point for activating the system. This calculation is crucial to the performance of the system since it defines the envelope of the line packing calculation. For a given HIPPS, longer the system closure time is, the lower will be the 'High-High' trip point

The system response time is one of the factors in determining the length of the fortified section. Shorter response time allows a shorter fortified length and longer response time requires longer fortified section.

In general, a gate valve closes much faster than a ball valve. However, a faster closing valve may not be preferred due to the dynamic impact effects of the flowing medium on the flowline. Here, the flow assurance determines the most suitable closing time for a valve, beyond which the flowline system can have adverse effects due to the back surge. At the same time, the valve manufacturers prefer faster closing valves to reduce the duration of the high fluid velocity at the final stages of the closing, in order to reduce the damage to the of the valve components. An acceptable figure shall be reached for the valve closing time during design.



Testing is performed on the HIPPS valves to verify the valve response time. HIPPS valves shall undergo hydrostatic testing, static and dynamic cycle testing, hyperbaric testing, gas leak testing, thermal testing, and testing for sandy service. Valves used for HIPPS applications have to prove themselves to close within the required time, under various conditions that can be present during subsea. Under laboratory conditions, it is relatively easy to determine the response time. Valves can be monitored and timed fairly accurately.

Once installed and commissioned, a HIPPS system will require periodic testing. Part of this testing will require valve response time testing of the HIPPS valves. The actual valve response time for the HIPPS valves is obtained from the test to verify the design as installed and during the life of the field to confirm the validity of the design. The temperature & pressure of the fluid flowing and its contents can affect the valve closure time, while subsea.

This Section examines two separate but related issues:

1. What needs to be considered to determine the theoretical valve response time for HIPPS valves;
2. What needs to be considered to determine the impact of a given valve response time for HIPPS valves on the HIPPS system.

The intent of the above discussions is to present a thorough picture of the issues associated with determining valve response time for HIPPS valves and the resulting impact to the flowline system to facilitate the drafting of regulatory guidance of HIPPS systems relative to HIPPS valve response time.

3.3 HIPPS Valve Response Time

3.3.1 Definition of Valve Response Time

The valve response time is the time between the start of the closing of the valve to the end of the closing cycle. Each valve is unique even when they are built to the same design due to tolerance variations and variations in the field and operating conditions. In spite of the uniqueness of the parts and the assembled valve, the response time shall be in the pre-determined range of the valve design.

The valve response time varies from manufacturer to manufacturer. However, for a gate valve some of the manufacturers have suggested a valve (5 inch valve) closure time of 2 seconds or less. This 2 second is due to the force of the closure spring alone and with no pressure in the line. When there is pressure in the line, the valve closes faster because of



the inherent design of the gate valves, where the closing force of the spring is assisted by the line pressure.

3.3.2 Variables Affecting the Valve Response Time

The valve response time determination is affected by factors such as manufacturing tolerance, operating pressure, operational depth, control fluid pressure, rate of control fluid dumping to the sea, and temperature of the valve. These factors are taken into consideration during the design phase of the actuator.

For a given dimensional tolerance of the parts, the assembly stack up clearance can vary within a certain pre-determined design range. In case of any deviation of the part dimensions during manufacturing, it is critical that the design is revisited to verify the stack up tolerances with the deviated part in assembly, is acceptable for operating parameters.

The operating or bore pressure is the pressure of the wellbore fluid flowing through the valve. With a spring return actuator, when the control fluid pressure is cut off from the actuator, the actuator closes due to the spring force. This force is designed to overcome the valve friction and the seawater head on the stem and the control fluid head on the piston. The operating pressure, acting on the stem depending on valve design, adds to the spring force in closing the actuator. The operating pressure can vary depending on the reservoir pressure and hence the closing time will also vary accordingly. Since the reservoir pressure normally depletes at the later years, the operating pressure also reduces and in turn the force closing the piston also reduces. In an application where the actuator is designed for 10,000 psi tree, the well bore fluid pressure may be less than 5,000 psi. In this application the closing time may be higher compared to the same tree operating in a field with 10,000 psi bore pressure. These differences may be small for other consideration. However, it affects the time required for closing of the HIPPS system and must be considered in HIPPS system evaluation.

Operational depth is constant for a given field. An actuator designed for a 10,000 ft operation will have different valve closing time while operating in 10,000 ft compared to working in 5,000 ft field. The height of the water and control fluid column forces exerting on the actuator piston and the stem influences the valve closing time. The spring force and the bore fluid forces have to overcome the seawater and control fluid forces. For a given HIPPS the operational depth is known and hence the valve closing time is also known. This can be verified by a hyperbaric chamber test for the operational depth.

An actuator closes when the control fluid pressure behind the piston is released. In subsea conditions, when the control fluid pressure is released, the force exerted on the stem by the seawater is dependent on the depth at which the actuator is operating.



Depending on the water depth, the pressure varies. In deeper waters, the seawater pressure is higher. This results in longer valve closing times. The closure time increases with the operating depth.

The actuators are designed such that the control fluid pressure enters the cylinder and pushes the piston which in turn pushes the gate or ball in the valve. For a given actuator, the force required to push the gate is dependent on the area of the piston and the control fluid pressure, less the frictional losses. So, higher the control fluid pressure, lower is the area of the piston. Since the stroke of the valve is same, higher pressure reduces the volume of the cylinder which contains the control fluid. This volume of liquid has to be dumped when the valve needs to close. The rate of dumping influences the valve closing time. Slower the rate, longer will be valve closing time. When the valve is closing, the time it takes to close will decrease for higher control pressure (lower volume) actuator compared to the same valve being closed with lower control pressure (larger volume) actuator. The valve closure time in this case is also known for a given HIPPS and can be determined through hyperbaric chamber test of the actuator.

Faster rate of dumping allows the valve to close quickly and slower rate slows down the valve closing. If for any reason the passage is obstructed, the rate of fluid dumping will decrease, increasing the valve closure time. It is safe to conclude that the closure time increases with the increased area of blockage of the vent line.

The operating temperature of the valve has direct bearing to the valve closing time. The clearance between the valve seat and body and also between the valve gate (or ball) and seat has direct influence on the frictional force which the valve has to overcome while closing. In addition, for a given design of the valve assembly, this clearance varies due to the expansion and contraction of the parts depending on the operating temperature. It must be understood that the parts manufactured are per the approved design. In case of any deviation of the part dimensions during manufacturing, it is critical that the design is revisited to verify the stack up tolerances with the deviated part in assembly, during approved operating temperature range.

After the initial testing, following the installation, the HIPPS system shall be tested periodically to assure that the system is working as designed. Valve response time is one of the parameters of this periodic testing. Typically the HIPPS system stays subsea for the duration of the field. During that time things that can influence the valve closure time, like, changes in line pressure, clogging or gumming of the dumping line on the actuator, increased friction force between the gate or ball and seat due to corrosion or wax, metallurgical deterioration of the gate or ball and seat, and leakage past seals which tend to slow the closing of the valve, etc. have to be considered while designing the fortified



section. Allowance must be pre-determined for the increased valve closing time due to some or all of the factors discussed. These factors vary from field to field. Some fields may have wax problem where as some other may have sour gas problem. Each field must be analyzed case by case.

Clogging of the line, which dumps the fluid when the actuator is closing, is a major potential factor for increasing the valve closing time. Clogging can take place due to inadvertent mixing of the control fluid or due to the formation of layer of scale on the walls of the flowing tube due to long exposure to the control fluid.

3.3.3 Determination of Valve Response Time

It is fairly easy to determine the valve response time in the laboratory conditions. It is also not too difficult to monitor after subsea installation, using control system function pressures for example (trending).

When the periodic testing results show valve response time changes, it may indicate a developing problem, even if the results are within the design limits. If there is no change or change is within normal wear and tear, system is functioning. However, if the time has jumped or is progressively deteriorating from the previous measurements, it raises a flag that something is not right. Under these circumstances, it is the responsibility of the operator to investigate and prove to MMS satisfaction that HIPPS is still functioning and production can continue.

Similarly, cases where the valve closing time stays constant despite varying parameters such as decreased bore pressure should raise a flag. For discussion, in a gate valve if the valve closing time is 2 seconds with zero bore pressure during previous periodic test and 2 second with bore pressure of, say, 3,000 psi during the current testing, then it is possible that the valve has deteriorated even if the valve closing time is within the required 2 seconds in both cases. The time with bore pressure of 3,000 psi should have been lower than the one with zero bore pressure. The valve or system has deteriorated since the last test.

In cases such as identified above, the operator must evaluate the HIPPS system to find out what is causing the increase even when it is within the design range. The operator must show that the situation will not deteriorate further and convince that valve closing time will not increase.

When the valve closure time testing reveals that the time is more than the design limits, the operator should investigate the causes for the increase. He should also assure MMS



with proper analysis and documentation what is causing the increase and why the valve closure time will not deteriorate before production can be resumed.

3.3.4 Description of Subsea Valve Response Time Testing

The valve response time is the time from the start of the closing stroke, linear or rotary, to the end of the closing stroke. Under laboratory conditions a sensor attached to the valve stem can sense the start and end of the stroke. After the subsea installation of the HIPPS, the valve response time shall be tested. This time must be within the design range of the valve closing time. This testing will verify the design parameters for determining the analytical valve response time.

3.4 IMPACT of HIPPS Valve Response Time

3.4.1 Description of Typical HIPPS Flowline System

In a typical HIPPS flowline system a HIPPS manifold is installed downstream of the tree on a higher pressure source well (see Figure 3-1). A jumper from the well is connected to the HIPPS manifold. A jumper connects the flowline PLET to HIPPS manifold (in some fields, the PLET and the HIPPS are located such a way, when the higher pressure source depletes at later years and when the pressure drops to the level of lower pressure source, then the HIPPS system can be by-passed by connecting the tree directly to the flowline PLET through a jumper). In such cases, both the jumpers and PLET are suitable for higher pressure flow. The fortified section starts from the PLET and ends at a spec break further down stream. The length of the fortified section is determined by flow assurance engineering.

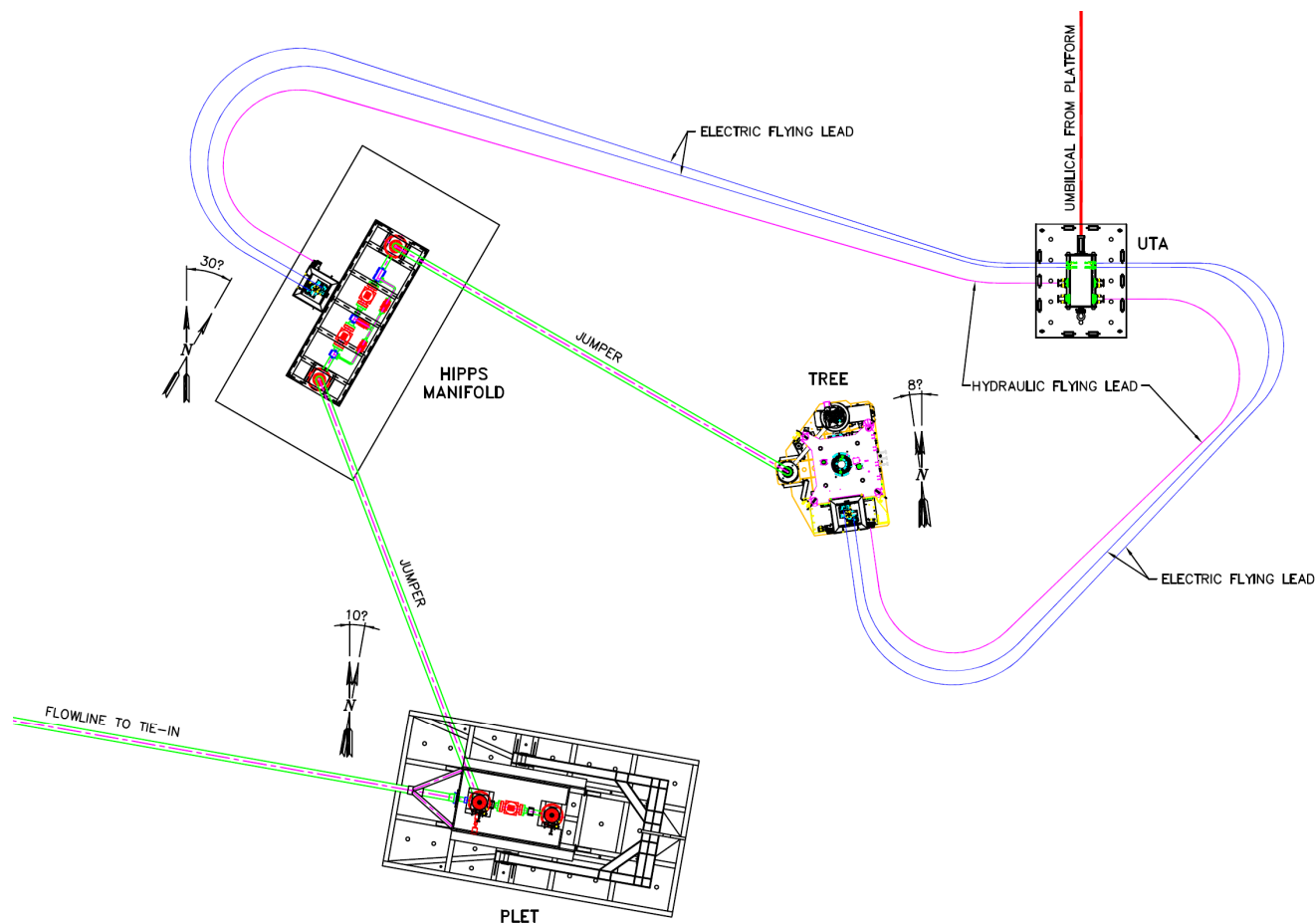


Figure 3-1 Typical HIPPS Installation

The logic solver SCM for the HIPPS system is independent from the tree SCM.

The HIPPS manifold carries typically two zero leak valves, in tandem (See Figure 3-2) on the flowline. In this typical case there are two by-pass valves in tandem running parallel to the HIPPS valves. These by-pass valves provide a way to release the pressure upstream of the HIPPS valves after they are closed. This will allow opening of the HIPPS valves under low or zero pressure difference across the gates or balls. Two by-pass valves provide dual barriers to the production fluid. A third by-pass valve is running between the two HIPPS valves and between the two by-pass valves. This allows the release of trapped pressure between the two HIPPS valves.

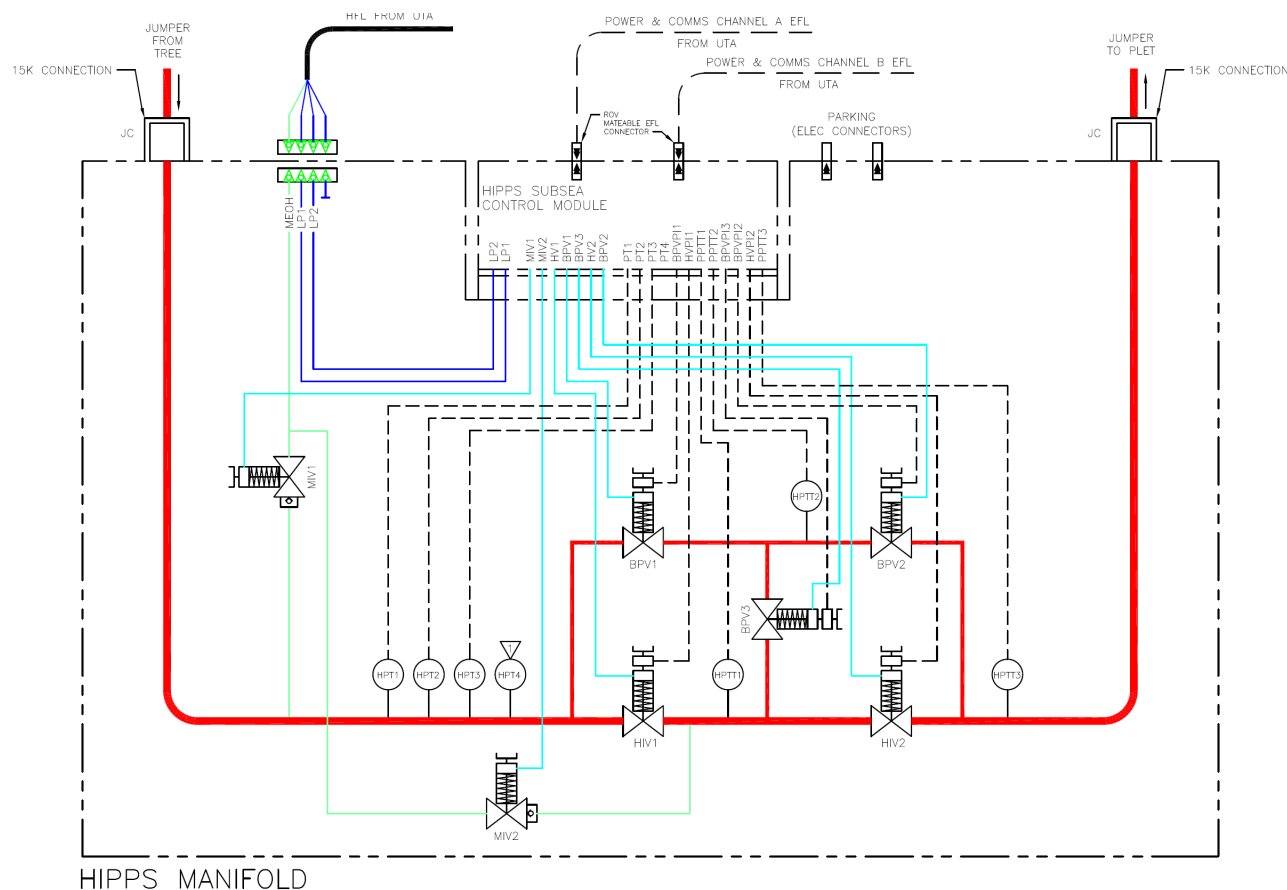


Figure 3-2 Typical HIPPS P&ID

Two methanol injection points are installed, one between the HIPPS valves and one before the HIPPS valves. These two methanol injection points are provided for the hydrate mitigation program of all the valves. In this typical case there are four HIPPS Pressure Transducers (HPT) on the upstream side of the HIPPS valves. This will provide Two out of Three (2oo3) voting with a back-up. In addition, multiple banks (not shown here) of transducers are recommended if one set fails in operation.

3.4.2 Discussion of Various HIPPS Activation Scenarios

HIPPS is an over pressure protection device installed to protect the lower pressure devices. Hence any scenario that causes the pressure to rise beyond the acceptable level in the lower pressure zone will activate the HIPPS. It could be restriction in the flowline or a complete blockage due to hydrate formation.

Restrictions in the flowline can be from wax deposits, or could be from the well bore fluid contents.



HIPPS can also be triggered if the Emergency Shutdown (ESD) valve is closed. It can also be triggered by an operator error when the flowline is closed inadvertently.

3.4.3 Variables Affecting Impact of HIPPS Valve Response Time on Flowline System

Once the HIPPS is installed and commissioned, the valve response time must be monitored. As long as it is within the design parameters, the HIPPS will function as intended. However, if the valve response time is more than the design limit, then it must be brought to the attention of MMS. If the operator intends to continue the operation without intervention, then an acceptable mitigation process must be put forward for MMS acceptance. This could be in the form of lower trip pressure setting or it could be that the well bore pressure has declined to an acceptable level with the new valve response time. The latter will reduce the rising pressure gradient.

Another option that may be acceptable to the operators is to reduce the production flow rate from the higher pressure well. The operator has to weigh the economical expenditure of the lower flow rate against the expenditure in replacing the valve by closing the production. This lower flow rate can be made to offset the higher valve closure time.

In all such cases the fortified section shall be shown as adequate with the increased valve response time.

3.4.4 Valve Closure Time Sensitivity

When the valve response time is increasing beyond the design limits, it has adverse affect on the trip pressure setting. Normally the trip pressure setting is below the MAOP but above the normal operating pressure. This cushion, the difference between MAOP and the normal operating pressure, is provided for the system to stay below the MAOP by the time HIPPS is activated and pressure is cut-off. If the valve response time increases it forces a reduction in the trip pressure to prevent the flowing system reaching the MAOP due to longer valve response time. This reduces the margin between the normal operating pressure and the trip pressure. The system will likely trip more often.

The sensitivity that is required in the determination of the valve closure time will be case specific but to illustrate the accuracy that can be required the following example provides some guidance.

Figure 3-3, shows the effects of different valve closure times on the final packing pressure upstream of a hydrate blockage which is located just downstream of the fortified zone. The HIPPS trip pressure is set to 8,000 psia and the design pressure or the MAOP of the pipeline downstream of the fortified section is 10,000 psia.

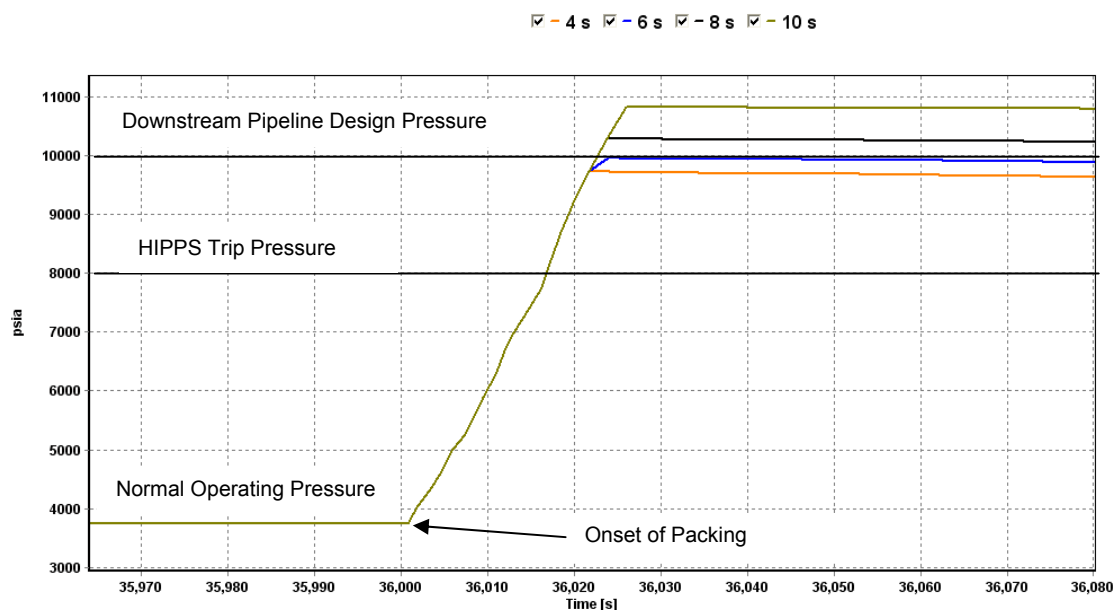


Figure 3-3 Valve Closure Time Sensitivity

All of the trends have the HIPPS valves closure initiated at the same point – the HIPPS trigger pressure of 8,000 psia but each of the packing trends shown represents a different HIPPS valve closure time.

It can be seen that for valve closure times of 4 and 6 seconds the final settle out pressure after the HIPPS valve has closed is below the downstream pipeline design pressure of 10,000 psia. However both the 8 and 10 seconds valve closure times result in a settle out pressure in excess of the downstream pipeline sections design pressure.

In the above case, the HIPPS can be made to function for valve closure times of 8 & 10 seconds provided the trip pressure is set below the 8,000 psi which will give enough time for the valve to close and the closeout pressure will be below the design pressure of the downstream pipeline.

Therefore sufficient design margin must be included in the assumed HIPPS valve closure times used in design to allot for lag during design life and operational uncertainty.

3.4.5 HIPPS Trip Pressure Setting

Ref: Section 5.

Figure 3-4 details the case with a 1000 ft fortified section with the HIPPS trip pressure being varied.

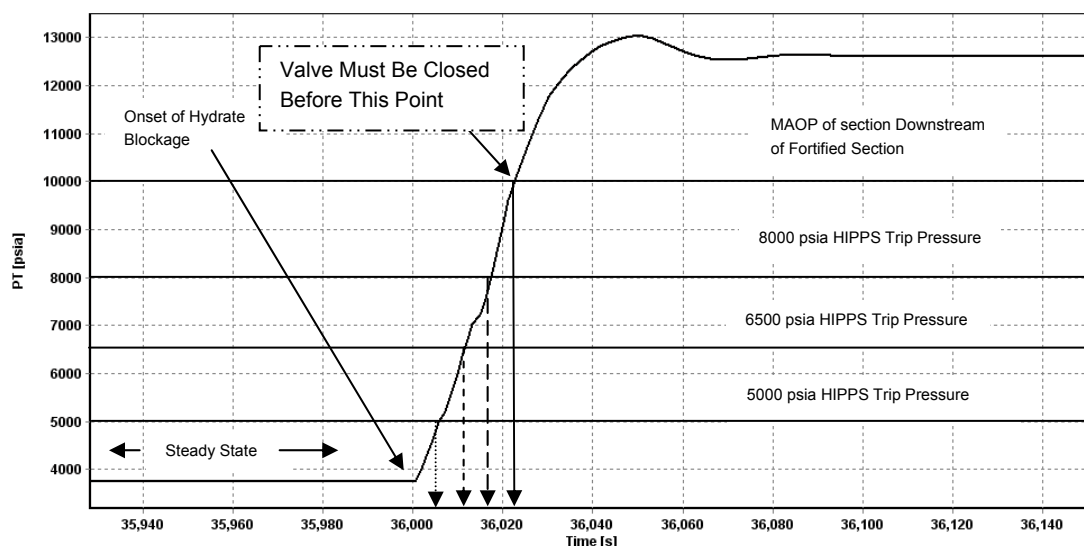


Figure 3-4 Pressure Due to Hydrate Blockage – HIPPS Trip Pressure Sensitivity
1000 ft Fortified Section

The above graph illustrates the method to arrive at HIPPS trip pressure. The curve shows the pressure in the line upstream of a blockage with a high pressure source and no HIPPS. Blockage occurring on the non-fortified section causes the line pressure to rise in the flowline upstream of the blockage including the non-fortified section. Without a HIPPS, the line pressure will exceed the MAOP (10,000 psi) downstream of the fortified section as illustrated by the graph. With HIPPS in place, the trip set point pressure is set at a level such that the valve closes completely before the pressure downstream of the fortified section reaches the MAOP per code requirements. The rate at which the pressure is rising together with available valve closure time determines the trip set point pressure. The higher the trip set point pressure, the shorter is the available closure time, as indicated below.

The allowable closure times for different HIPPS trip pressure set points are:

- 5000 psia – 18 sec;
- 6500 psia – 12 sec; and
- 8000 psia – 6 sec.



All of the trip set point pressures are well above the FWHP but by reducing the set point pressure the valve closure time can in this case be doubled or tripled. Some engineering judgment is required however as to where the trip pressure set point should be set so as to avoid lowering the set point to far and causing spurious trips caused during normal operation.

Flowrate

Figure 3-5 details the packing due to the variations in the flowrate prior to a hydrate blockage.

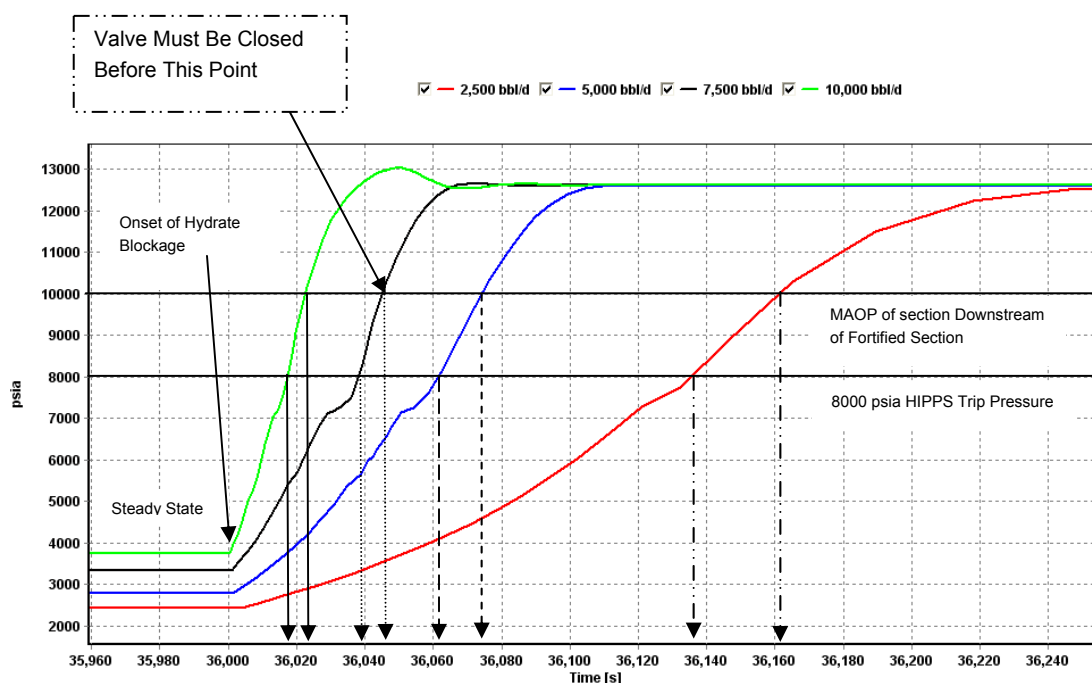


Figure 3-5 Pressure Due to Hydrate Blockage – Flowrate Sensitivity

1000 ft Fortified Section

Figure 3-5 takes the same case detailed previously where the flowrate prior to blockage was 10,000 bbl/d and the fortified section is 1,000 ft long with a HIPPS pressure trip of 8,000 psia. If the flowrate prior to blockage is reduced, Figure 3-5 shows that the required valve closure time increases significantly. This therefore highlights that any design case considered should assume the maximum flowrate is present for that period in field life so as to capture the most conservative packing case.



Field Life

Figure 3-6 investigates the packing throughout field life for a hypothetical case. Many factors, such as gas lift, late life water flooding etc., can affect these curves. As expected the controlling case is early field life when reservoir pressure is high, flowrates are high and water cuts are low. As field life progresses the reservoir pressure declines, the flowrates and therefore the packing rate declines, as does the final shut in pressure (due to increased water cut therefore greater static pressure loss in the wellbore).

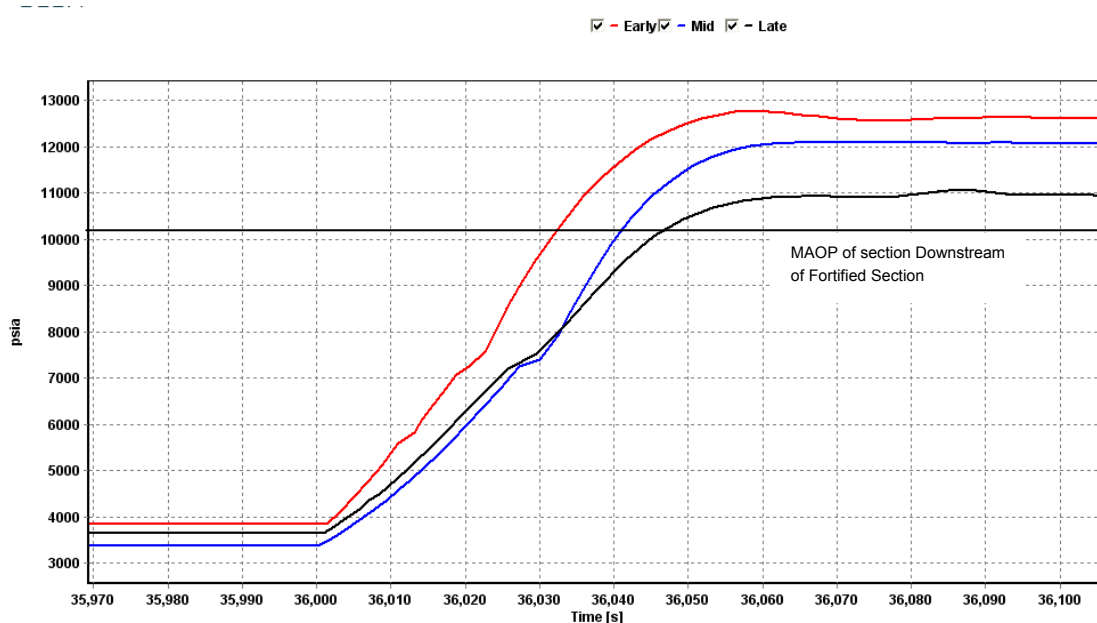


Figure 3-6 Pressure at Hydrate Blockage – Field Life Sensitivity

1000 ft Fortified Section

If however the reservoir pressure maintenance is present, there may be the potential for conditions during later field life when there is more liquid pressure present that have a lower flowing wellhead pressure but a faster rate of packing as shown in Figure 3-7. Therefore a thorough analysis of all the design cases throughout field life is required so as to not miss the controlling packing case.

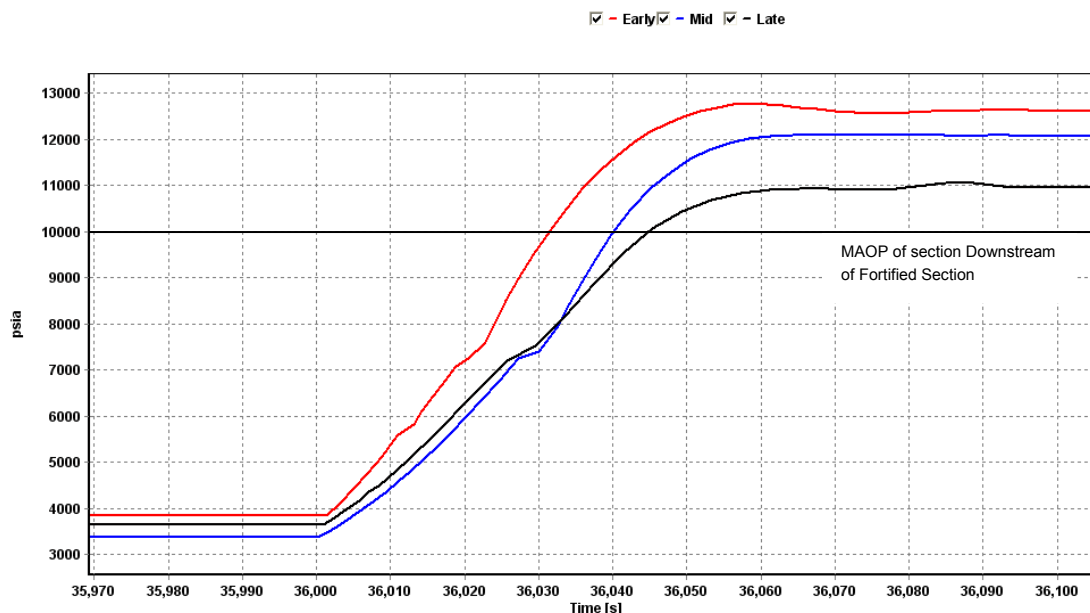


Figure 3-7 Pressure at Hydrate Blockage – Field Life Sensitivity with Pressure Maintenance – 1000 ft Fortified Section

One option that is open to operators is the electric actuators on the valves. Unlike hydraulic actuators the electric actuators respond quickly. This gives the opportunity to increase the trip pressure if the valve closure time increases in the field. It can be designed into the HIPPS valves. This may allow the trip pressure to be set closer to the MAOP.

When the valve closing time is increasing beyond the design limits and if the tree is equipped with electric actuators on production valves, then these valves can be made to shut down when the pressure reaches the MAOP of the lower pressure section of the flowline. This will be an added safety margin for the production flowline.

In general, the electric actuators provide more design flexibility in setting the trip pressure for the HIPPS.



4. TASK 400 – MATERIALS SELECTION

4.1 Task Summary

This study investigates materials issues with respect to HIPPS equipment. The section summarizes the recently-released API RP 17O for materials requirements. The section then investigates how API RP 17O addresses several materials issues, such as corrosion, temperature effects on materials, and SCC/SSC. Included with this discussion is a brief summary of how each of the specific material issues is currently addressed by industry for other subsea equipment. The section concludes with general remarks about regulatory guidance regarding HIPPS material selection. The conclusion reached is that there are no special conditions warranting special regulatory guidance of HIPPS in regards to materials selection.

4.2 Introduction

4.2.1 Scope

This document addresses issues surrounding HIPPS material selection. The study summarizes API RP 17O in regards to materials, reviews several specific material issues and how the industry currently typically handles them, and summarizes any special regulatory guidance for HIPPS materials selection.

4.2.2 Problem Statement

Consideration of the materials and methods of construction of a HIPPS is an important part of ensuring both the short and long-term physical integrity of the system.

The material selection aspects of any particular HIPPS are likely to be tailored to a specific application, but certain materials-related concerns should be considered for all HIPPS equipment, such as:

- Sulfide stress cracking/hydrogen embrittlement arising from produced H₂S and/or sacrificial anode cathodic protection;
- Internal corrosion/erosion arising from H₂S, CO₂, produced sand and/or completion/workover fluids;
- External corrosion from the marine environment;
- Stress corrosion cracking susceptibility due to chlorides in produced formation water; and



- Temperature-related concerns, such as material toughness, reduced yield and ultimate strengths, accelerated corrosion/cracking, and non-metallic material degradation.

Several specifications/guidelines such as API 6A, NACE MR0175, DNV RP B401 and API RP 14E have been used successfully in the design of subsea facilities in regards to materials. The recommendations/requirements of these collective specifications will likely form a good basis for materials selection for a HIPPS. However, considering how critical the reliable operation of a HIPPS will be to safety and environment, a detailed investigation of the special demands and requirements of a HIPPS in regards to materials is merited.

4.3 Code Review

The recently-released API RP 17O, Recommended Practice for Subsea High Integrity Pressure Protection Systems (HIPPS), is likely to be the de facto controlling industry standard for HIPPS in the Gulf of Mexico. Thus API RP 17O is here the basis for reviewing materials issues for HIPPS. This section summarizes the contents of API RP 17O as related to materials requirements.

4.3.1 HIPPS Final Element Equipment

A HIPPS final element is defined as the part of the Safety Instrumented System (SIS) which implements the physical action necessary to achieve a safe state. For this report, the HIPPS final element is understood to be the HIPPS isolation valves and actuators. API RP 17O has the following requirements:

- Material performance, processing, and compositional requirements should conform to API 6A/ISO 10423;
- Higher strength materials than those specified in API 6A/ISO 10423 may be used if the requirements of API 6A/ISO 10423 are met by the manufacturer's written specifications;
- Requirements for pressure-containing forged material, forging practices, heat treatment, and test coupon are controlled by API 6HT with the additional requirement that the test coupon must accompany the material through all processing;
- Materials should be specified per API 17D/ISO 13628-4 material classes in regards to corrosion from bore fluids;
- Corrosion from the marine environment should be considered;



- Pressure-containing and pressure-controlling equipment shall be specified with a material class from AA through HH per API 17D/ISO 13628-4;
- Temperature classification for pressure-containing and pressure-controlling equipment should be API 6A/ISO10423 and API 17D/ISO 13628-4 class U (0-250°F), minimum;
- API 17O allows seawater cooling to be considered when determining if equipment meets defined temperature classification;
- Pressure-containing and pressure-controlling equipment should comply with PSL 3 of API 17D/ISO 13628-4;
- Closure bolting is limited to 321 HBN (Rockwell “C” 35) due to hydrogen embrittlement concerns and shall comply with PSL 3 requirements of API 17D/ISO 13628-4;
- The requirement for valves to be rated for sandy service shall be defined by the end user in compliance with API 6A/ISO 10423; and
- Erosion in HIPPS components should be considered.

4.3.2 HIPPS Control System and Final Element-mounted Control Devices

The HIPPS control system primarily consists of the HIPPS Subsea Control Module (HSCM), which contains the SEM, solenoid valves, DCVs, couplers, etc. Final element-mounted control devices include pressure transmitters and HIPPS valve position sensors. API RP 17O has the following requirements:

- Materials should be specified per API 17D/ISO 13628-4 material classes in regards to corrosion from bore fluids;
- Higher strength materials than those specified in API 17F/ISO 13628-6 may be used if the requirements of API 17F/ISO 13628-6 are met by the manufacturer’s written specifications;
- Final element-mounted control devices should consider temperature increases due to mounting near heated equipment or thermal shielding due to insulation;
- Material class and temperature rating for devices in contact with bore fluid shall be as per HIPPS final element requirements;



- Pipe, tubing, connectors, etc. shall withstand atmospheric and sea water corrosion;
- Materials of pipe, tubing, and hoses in contact with bore fluids or injected chemicals shall be compatible with those fluids; and
- Seals should be compatible with any fluid with which they come into contact.

4.3.3 Welding

- Welding on pressure-containing and pressure-controlling elements should meet PSL 3 requirements of API 6A/ISO 10423;
- Structural welds shall comply with API 6A/ISO 10423 or a documented code such as AWS D1.1; and
- Corrosion-resistant overlays shall be in compliance with API 6A/ISO 10423.

4.3.4 External Coatings

- An external coating system should be part of external corrosion control for HIPPS equipment in conjunction with materials selection and cathodic protection;
- The external coating system shall comply with written specifications or API 17D/ISO 13628-4; and
- External coating color selection shall be in accordance with API 17A/ISO 13628-1.

4.4 Materials Issues

The subsections below address specific materials issues that may impact a HIPPS. Each subsection discusses the specific issue(s) in a broad way and then discusses how API 17O addresses the issue. The subsections conclude with a short description of how the issue is addressed by industry for other subsea equipment.

4.4.1 External Corrosion

HIPPS equipment should be capable of withstanding the marine environment for its design life without significant degradation due to external corrosion. The typical means employed to limit or prevent external corrosion of subsea equipment are materials selection, coatings, and cathodic protection.

API RP 17O addresses external corrosion of equipment indirectly. In discussing final elements API RP 17O says that corrosion from the marine environment should be considered. For final element-mounted controls equipment, API RP 17O says that pipe,



tubing, end fittings, connectors, and connector plates should be made of materials which will withstand sea water corrosion.

API RP 17O does contain a section on external coatings, which advises that external corrosion control of HIPPS equipment be provided, but then goes on to say that the implementation of such a program is beyond the scope of the RP. As far as coatings are concerned, API RP 17O requires that coating systems comply with either written procedures or API 17D/ISO 13628-4.

Current industry practice for subsea equipment is to employ a sacrificial anode cathodic protection system in concert with a high-integrity coating system, usually a multipart epoxy for valves and actuators. DNV RP B401 is a widely used CP specification. Controls equipment exposed to seawater, such as sensors and connectors, are often manufactured from inherently corrosion-resistant alloys. Where controls equipment is subject to external corrosion, it is protected by the CP system.

4.4.2 Internal Corrosion/Erosion

HIPPS equipment needs to be resistant to corrosion from bore fluids. A variety of fluids may come in contact with the HIPPS during its lifetime such as production fluids including produced water, completion fluids, workover fluids including acids, hydrate inhibitors, chemical inhibitors, and others. All fluids and their compositions over the life of the HIPPS need to be characterized and planned for. The primary means used to limit or prevent internal corrosion of subsea equipment is materials selection. Chemical corrosion inhibitors are typically used for corrosion inhibition of carbon steel flowlines and are of limited usefulness for protecting subsea equipment.

Where there is a possibility of solids (sand) in the fluids, erosion needs to be considered. Under certain conditions, erosion from sand and corrosion from bore fluids work together to create possibly severe erosion/corrosion conditions. Erosion and erosion/corrosion are typically limited by a combination of materials/coatings and design to limit erosional velocities.

API RP 17O addresses internal corrosion solely by requiring that the end user specify an API 17D/ISO 13628-4 material class for pressure-containing, pressure-controlling, and controls equipment that contacts bore fluid. The material classes range from AA through HH and it is left to the end user to select a material class based on service conditions and relative corrosivity. API RP 17O addresses erosion in a general way by requiring that erosion in the HIPPS at changes in flow direction be considered and mitigated during design.



Current industry practice is to reduce or prevent internal corrosion of subsea equipment by specifying materials that are inherently resistant to corrosion from the potential bore fluids. These materials meet the required API 17D/ISO 13628-4 material class, AA through HH, required by the specifics of the systems. Within the specified material class, there are several materials that can meet the corrosion requirements. Erosion and erosion/corrosion are mitigated by materials selection and design to limit erosional velocities below critical levels. API RP 14E is often used for erosion/corrosion design of subsea equipment. Corrosion-resistant alloys typically have higher allowable erosional velocities than carbon steels.

4.4.3 Temperature Concerns

HIPPS equipment will be subjected to a range of temperatures throughout its lifetime. High temperatures may result from heating from the produced fluid. Low temperatures can result from ambient conditions on the seabed or possibly from dynamic effects such as Joule-Thompson cooling. Low temperatures are a concern primarily for material impact toughness requirements. A secondary concern for low temperature is the potential effect on the function of non-metallic seals due to altered material properties. High temperatures are of concern because of the potential loss of yield and ultimate strength of metals. Some metals are more resistant to temperature-related strength loss than others. High temperatures are also a concern for non-metallic elements, especially elastomeric seals. These seals may have degraded mechanical properties and shortened lives at elevated temperatures.

4.4.3.1 Impact Toughness

API RP 17O addresses impact toughness by requiring that HIPPS equipment meet API 6A/ISO 10423 and API 17D/ISO 13628-4 temperature classification “U” (0-250°F) as a minimum. This requirement is the same for final elements and controls equipment in contact with bore fluids. This is generally in line with current industry practice. Should the minimum temperature of a HIPPS fall below the minimum designated by temperature class “U”, then a more stringent temperature class will have to be selected.

4.4.3.2 Yield/Ultimate Strength

API RP 17O does not directly address the effect of elevated temperature on yield/ultimate strengths of HIPPS equipment. Current industry practice is to derate the strengths of materials for temperature classes with a maximum temperature above 250°F, per API 6A/ISO 10423. API 6A/ISO 10423 contains an annex with detailed guidance for elevated temperature testing, design, marking, etc (Appendix G). **However, the temperature derating per API 6A/ISO 10423 is not conservative for all situations.** Some materials,



such as duplex stainless steels, have significant loss of strength at temperatures below 250°F. For instance, a typical rule of thumb for duplex stainless steel (UNS 31803) is that it retains about 85% of its room temperature yield strength at 250°F. API 6A/ISO 10423 Appendix G only addresses temperature derating for temperatures above 250°F. All materials used for HIPPS equipment should be evaluated in regards to temperature effects on yield/ultimate strength and if appropriate should be tested and derating factors should be applied in accordance with the guidance in API 6A/ISO 10423.

4.4.3.3 Non-metallic Seals

API RP 17O does not address requirements for non-metallic seals directly. There is a general requirement that seals which contact bore fluids or injected chemicals are compatible with those fluids. Current industry practice is to rate and test non-metallic seals for the same temperature class of the equipment within which they are installed unless it can be demonstrated that the seals will be subject to less extreme temperatures than those of the temperature class. API 6A/ISO 10423 contains considerable guidance for quality control and verification of non-metallic seals (Appendix F, Section F.1.13).

4.4.4 Sulfide Stress Cracking/Hydrogen Embrittlement

Sulfide stress cracking is a phenomenon where susceptible materials may fail due to a complex interaction of metal composition, hardness, heat treatment, microstructure, and other factors such as pH, hydrogen sulfide concentration, stress, and temperature. Sour production fluids are the main source of hydrogen sulfide. Hydrogen embrittlement is a similar process whereby a metal is made more prone to cracking by the diffusion of atomic hydrogen into the metal's microstructure. For subsea equipment, the main source of the atomic hydrogen is the cathodic protection system, which causes hydrogen to form on the protected equipment where it may diffuse into the metal.

API RP 17O indirectly addresses SSC by requiring that HIPPS equipment is specified per an API 17D/ISO 13628-4 material class. Material classes DD through HH meet the requirements of NACE MR0175/ISO 15156 for resistance to SSC, depending on hydrogen sulfide partial pressures and other factors. Hydrogen embrittlement is addressed only in relation to closure bolting, where a maximum hardness is imposed to address possible embrittlement due to the CP system.

Current industry practice is to select materials that meet the requirements of NACE MR0175/ISO 15156 when hydrogen sulfide may be present in significant amounts. Selection of an API material class of DD through HH requires that the NACE/ISO requirements be met. Internal coatings are not used to mitigate SSC concerns. Similarly, compliance to NACE MR0175/ISO 15156 addresses hydrogen embrittlement concerns.



In the case of hydrogen embrittlement, external coatings may be used to limit diffusion of hydrogen into the metal, but coatings should not be solely relied upon since they may be damaged or break down during the life of the HIPPS.

4.4.5 Chloride Stress Corrosion Cracking

Stress corrosion cracking (SCC) is a process where a susceptible metal is subject to a local anodic corrosion reaction and cracks under a tensile stress (applied or residual). Chlorides, from bore fluids or the seawater environment, increase the susceptibility of some metals to SCC considerably. High strength carbon steels and austenitic stainless steels (300-series) are especially susceptible to chloride SCC.

API RP 17O addressed chloride SCC only in regards to closure bolting. The specification states that selection of bolting materials and coatings should consider chloride SCC, but no specific guidance is given.

Current industry practice is to prevent chloride SCC through materials selection. NACE MR0175/ISO 15156 provides limits for alloy and stainless steels and CRAs based on chloride concentration, temperature, hydrogen sulfide concentration, pH, etc. Some material acceptability depends on how the material was processed and hardness. Coatings are not acceptable to prevent chloride SCC due to potential damage and breakdown.

4.5 Discussion of Regulatory Guidance

The materials comprising a HIPPS will be subjected to a variety of fluids and operational conditions that could potentially cause a variety of materials-related issues. High and low temperatures, corrosive bore fluids, the marine environment, and cracking-inducing agents all need to be considered when specifying materials for a HIPPS. Fortunately, the subsea industry has dealt with these issues for decades and the knowledge base related to specific materials issues such as internal/external corrosion, temperature effects on toughness and strength, and SSC/SCC is quite significant. Industry standards addressing these issues have proven their effectiveness in reducing or eliminating these material issues in compliant equipment.

A subsea HIPPS, depending on the specific system design, may be subjected to a wider range of fluids and operational conditions than any single piece of subsea equipment like a tree. However, the industry standards referenced throughout this report are flexible enough to be effective for materials issues regardless of the media or conditions to which the HIPPS is exposed. The most important consideration is to develop a very well defined design basis for the HIPPS which includes all development phases and operational



conditions of the system over the life of the HIPPS. For instance, if additional wells are to be brought online upstream of the HIPPS, the fluids and operational conditions of those wells will have to be considered during material selection. Another example of changing conditions over the life of a HIPPS would be hydrogen sulfide-free production fluids eventually souring due to water injection into the reservoir. Only by selecting HIPPS materials based on worst-case scenarios can materials issues such as those described in this report be avoided.

API RP 17O addresses some of the described materials directly and others indirectly or not at all. For instance, API RP 17O addresses impact toughness directly by requiring a minimum temperature classification. However, no direct mention of derating is made due to elevated temperatures. The derating issue is indirectly handled by reference to API 6A/ISO 10423, which addresses derating, in other areas related to materials selection.

To summarize, API RP 17O makes direct reference to several industry standards such as API 6A/ISO 10423 and API 17D/ISO 13628-4 that themselves deal directly or indirectly with the described materials issues. These standards have a proven record of guiding selection of materials that are free of the described materials issues. A HIPPS may have a broader range of conditions and fluids to consider, but if all variables are considered over its life, there is nothing inherent in a typical HIPPS design that would require special regulation regarding materials selection.



5. TASK 500 – LENGTH OF FORTIFIED SECTION REQUIREMENTS

5.1 Introduction

5.1.1 Purpose

The intent of this section is to present a review of the issues associated with the HIPPS fortified section and the resulting impact to the flowline system.

5.1.2 Scope

The fortified section immediately downstream of the HIPPS is a key component of the HIPPS system. The minimum length of the fortified section is determined by the system response time. This study looks at the various influencing parameters and recommends a guideline for the design of the fortified section.

5.1.3 Problem Statement

In any HIPPS system, the fortified section is downstream side of the HIPPS and provides an allowance for the time it would take the system to shut in from the moment it is tripped. This length is determined by the closure time of the HIPPS and the time it would take the length of fortified flowline to pack from the trip pressure up to the MAOP of the lower rated section. The fortified section is rated equal to or higher than the MAOP of the higher pressure source.

A special case may exist if the trip pressure is low enough and the HIPPS response time fast enough that the pressure downstream of the HIPPS does not exceed the MAOP of the protected system by more than 10%. This temporary pressure excursion might be considered an incidental overpressure load, if it can be shown that as soon as the HIPPS is closed the pressure would settle out along the pipeline and the pressure drop below the MAOP of the HIPPS protected section. If so this might be within usual United States design code allowable excursions or incidental pressures. No extra fortification would appear to be needed in this case.

In the event of an instantaneous blockage in the line that occurs beyond the far downstream end of the fortified section, the HIPPS valves must have time to close before the pressure builds to the MAOP of the lower rated section. If a similar blockage occurs in the fortified section and the line packs before the HIPPS valves could close, the fortified section, being higher rated, would accommodate the higher pressure.

The length of the fortified section is primarily impacted by the valve closing time and the trip pressure point. The fortified section must be of sufficient length and therefore volume



to be pressurization during packing to ensure that the system cannot be over pressurized in the time between the when the HIPPS valves are tripped and they fully close. A longer fortified section allows for a longer closing time for the HIPPS. However, a long fortified section will be more expensive and may not be practical in some fields.

Clearly, the speed of the valve closure is critical, as are the fluid media and flow rates which affect the mass transfer and packing rates. A range of practical valve closure times is picked to determine the fortified length of the flowline. In addition to the valve closing time, the analysis takes into consideration the 'High-High' trip pressure of the lower rated section, dynamic 'settling-out' effects, flow rate pressure, working depth, type and density of flowing, etc.

5.2 Design of Fortified Section

5.2.1 Definition of Fortified Section

The subsea HIPPS system consists of quick closing valves, sensors and controls, which provide a pressure break between the subsea system rated to the wellhead shut in pressure and the flowline and riser sections rated to a lower pressure. A fortified section may be located downstream of the HIPPS isolation valves to allow time to respond to the system closure determined by the pressure transient calculations.

The flowline must be fortified for some calculated distance downstream of the HIPPS valves, so that if a blockage occurs just downstream of the HIPPS valves and cause the system to pressurize to above the MAOP, this section will still be rated to the full wellhead shut in pressure

The length of the "fortified" section should be determined based on flow analysis. The use of alternative flow assurance methods (i.e. chemicals) should not be considered when determining the length of the fortified section. It is conceivable that this section may not be required, but this shall be proven based on flow analysis. The HIPPS configuration is detailed in Figure 5-1.

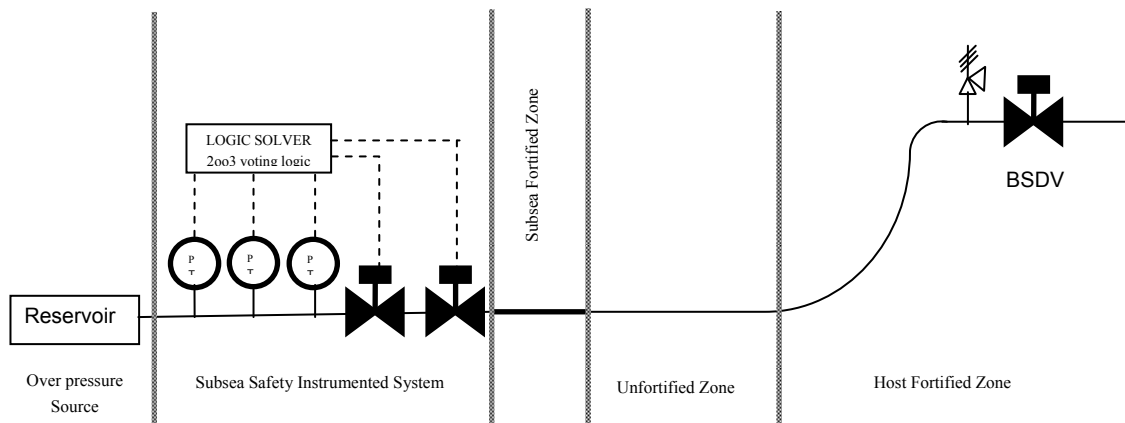


Figure 5-1 Typical Subsea HIPPS Configuration

5.2.2 Design Guidelines for Fortified Section

To determine the optimum fortified length, a dynamic flow assurance analysis can be performed on the system to estimate how quickly the flowing pressures rise to the design pressure of the de-rated flowline. To conduct this analysis the following guidelines are followed.

5.2.2.1 HIPPS Location/Field Architecture

It should be noted before any analysis is undertaken that there are a number of feasible locations for a subsea HIPPS. The location of the HIPPS within the subsea architecture can affect the number of HIPPS as well as the overall length of fortified section.

Possible subsea HIPPS configurations are:

1. Manifold Based – Here a number of wells tie into a manifold and commingle flow where the HIPPS is based. This is the most likely option for subsea HIPPS. The advantages of this configuration are:
 - a. The number of HIPPS required is reduced;
 - b. The system can be installed independent of the drilling program;
 - c. HIPPS sensors are located away from choke valves where conditions are not turbulent; and
 - d. Better integrity due to single fault point.

The disadvantages of this configuration are:



- a. HIPPS valve sizes increase – valves are usually of comparable size to the larger manifold pipe. This in turn could limit availability and require additional qualification; and
 - b. The demand frequency of the HIPPS system could increase if it is a multiple tree system.
2. Tree Based – This system is either a stand alone skid or perhaps integrated into the tree itself (although this is currently not permitted by the MMS in the GOM). The advantages of this configuration are:
 - a. The operational uptime is increased compared to a manifold based system as a single failure would not necessarily stop all production;
 - b. Valves size can be kept low as the valve will be connected to a jumper which is commonly of smaller size. This would mean that valves that are already qualified can be considered;
 - c. The extent of the high pressure zone is limited to the tree;
 - d. May allow flexible layouts and phased development;
 - e. The unit cost could be reduced if the package reaches off shelf status; and
 - f. A stand alone skid may be re-usable elsewhere once production pressures have dropped if the skid can be bypassed and removed from the system.

The disadvantages of this configuration are however:

- a. Increase in the number of systems required if a multiple well system;
- b. Increased installation effort;
- c. Operational testing of the HIPPS system would increase thus increasing possible downtime; and
- d. System reliability affected by reliance on multiple safety devices.

It should also be noted that some HIPPS systems are located at the base of the riser or topside on the platform. The systems cover the scenario that a high pressure field is tied directly into an existing facility of lower pressure rating but are not within the scope of this study.

5.2.2.2 Design Scenarios

The critical events that design procedure is envisaging are possible events that would result in over pressurization of the flowline. Over pressurization may basically be caused by:

- Operator error;
- Topside shutdown due to process trip or emergency shutdown;



- Subsea choke malfunction resulting in high flowrate and increased manifold pressure; and
- Hydrate blockage.

Of the above possibilities, a hydrate plug relatively close to the subsea well but downstream of the intended fortified section is considered the most conservative and controlling scenario, as it requires the fastest response from the HIPPS valves.

It could be argued it is highly unlikely that a hydrate could form immediately downstream of a HIPPS valve during normal steady state operation as conditions will be outside the hydrate formation region. However, during more critical start up conditions, MeOH or some other hydrate suppressor must be injected. If suppression fails and normal flowrates are quickly established, the hydrate plug formation could be rapid due to the low temperatures associated with start up of high pressure wells.

5.2.2.3 Modeling Tools

Packing of the system due to a hydrate blockage is a dynamic event that will result in large and rapid changes in pressure and temperature within the system. To accurately analyze this, it is recommended that the transient multiphase simulation tool OLGA be used to model the system.

This simulation tool is an industry standard for such analysis and has been successfully used in numerous field developments. OLGA can comprehensively model the detailed mechanics of the fluid behavior within the system and detail numerous operating scenarios.

In addition to the dynamic modeling of the system, accurate characterization of the field production fluid properties must also be undertaken. A number of PVT fluid simulators are available that can interact with OLGA, the most commonly used of which is Calsep's PVTsim.

5.2.2.4 Design Procedure

The design procedure that should be followed when conducting the flow assurance analysis to determine the optimum length of the fortified section can be summarized by the following steps:

1. Assemble Accurate and Comprehensive System Basis Information – Since the packing dynamics of each development are unique, a detailed dynamic must be undertaken for each development considering the implementation of HIPPS. To



accurately do this a detailed and representative model of the system must be constructed. The following information should be included:

- Reservoir Data – reservoir or bottom-hole pressure, productivity index, reservoir temperature, reservoir depth (TVD & MD);
- Well Data – Tubing configurations (ID's, WT, etc);
- Production Fluid Data – Bubble point, API, composition, viscosity, density, composition;
- Production Data – Gas, oil and water flowrates throughout field life;
- System configuration – Jumpers, flowline and riser system dimensions (ID, WT, length, roughness), seabed bathymetry, valve sizes and opening characteristics, HIPPS configuration (well or manifold based); and
- Ambient Conditions – Wellbore thermal gradient, seabed ambient temperature, seawater currents.

Note – Reservoir pressure throughout field life should be noted. Usually early field life presents the highest reservoir pressure and should normally be the controlling case for the dynamic analysis however fields that utilize reservoir pressure maintenance (water injection/gas injection) or multi-zone reservoirs may present a more conservative case in later field life. In addition reservoir pressures throughout field are required to conduct the dynamic analysis throughout all stages of the field life and ensure robust design.

2. PVT Fluid Characterization – Once the fluid composition is put into a PVT simulator, the simulation fluid should be tuned so that it matches the fluid properties (GOR, API, viscosity, density, bubble point) found during PVT lab tests of actual production fluid. Regression algorithms exist with PVT simulators that facilitate this task.
3. Model Construction – To accurately model the packing of the system due to a hydrate blockage, it is advised that the entire system (reservoir, wellbore, choke valves, flowline and riser) be included within the model. The reservoir should be represented by a pressure boundary and the hydrate blockage can be represented by means of a closed valve that can be moved to different locations along the flowline to investigate the length of the fortified section.
4. Selection of Pressure Set Points – A key decision in the design process is to define the HIPPS activation set point pressure. Normally this is set sufficiently below the design pressure of the de-rated flowline sections to provide a safety margin, but also



give some operational flexibility. The set point will be dictated by the HIPPS valve closure time and the rate of packing. The set point should also be a sufficient margin above the flowline inlet pressure downstream of the subsea choke to avoid spurious trips caused by pressure fluctuations in normal flow.

5. Design Case Selection – During the passage of field life, a number of process variables change significantly. Each of these variables can greatly affect the dynamic response of the system during packing after a blockage. Variables to consider when selecting design cases for simulation are:
 - Reservoir Pressure – If there is no reservoir pressure maintenance this will lead to a decline of the reservoir and wellhead shut in pressures with time and in later field life may remove the need for the HIPPS. However fields that utilize reservoir pressure maintenance (water injection/gas injection) or possibly multi-zone reservoirs could lead to equivalent or higher pressures in later field life;
 - Fluid Gas to Oil Ratio (GOR) – This variable separates fluid types into typically oil based systems (low GOR) and gas based systems (high GOR). An oil based system will pack more rapidly due to the higher incompressibility of the production fluid as compared to gas. When selecting design gases the variability of GOR throughout the field life should be considered;
 - Water cut – As the field life progresses, water breakthrough may occur and the wells will start to produce water along with oil and gas. With an increase in water cut, the gas to liquid ratio of the fluid will decrease. As a result, the density of the production fluid will increase, thus lowering the flowing and shut in pressures, but increasing the packing rate of the system should a blockage occur. Design cases should consider the variability of water cut throughout field life; and
 - Production Rates – The production rates throughout field life are determined by reservoir analysis. Since a higher production rate will intuitively constitute a higher packing rate, the range of likely production rates at various points throughout field life should be encompassed in the selected design cases.

To encompass the range in each of process variables detailed above, it is recommended that the selected design cases used to simulate the packing of the system be selected at various regular periods from the field production profile (early life, mid life, etc.) while the shut in pressure of the well/wells (which will decrease as field life progresses) are still above the design pressure of the de-rated portion of the flowline, downstream of the fortified section.



The selection of various design cases throughout the field life is essential as it is hard to quantify without simulation at what point in the field life will represent the most conservative and therefore controlling packing conditions. For example, two cases from different points in the field life can have comparable packing time to the HIPPS set pressure:

- Early Field Life: for a well with mid range GOR production fluid, the reservoir pressure and GOR are typically high, whereas the water cut is generally low. This means that the wellhead flowing and shut in pressures will be at their highest. Therefore, the amount of packing to the HIPPS set point is low but the production fluid will contain more gas and will be more compressible and thus will not pack as rapidly; and
- Mid to Late Field Life: Alternatively in later field life when the well has started to cut water, the fluid is denser and therefore will pack more rapidly than in early field life, but the flowing wellhead pressure will be lower as opposed to earlier field life, so it will have further to pack to reach the HIPPS set point pressure.

Since much of this analysis is based on reservoir modeling which has been historically prone to significant uncertainty, a healthy level of conservatism should also be incorporated into selected design cases.

Note – Other process variables such as tubing size and pipeline size will also affect the packing times for any system, but it is assumed that earlier flow assurance analysis will have already have defined these parameters before any detailed analysis of the HIPPS system is undertaken.

6. Simulation Methodology – When conducting the analysis, the following points are beneficial to the simulation methodology:
 - PVT fluid files should be constructed with sufficient Pressure and Temperature points in the likely system operating range;
 - Ensure that steady state conditions are reached within the system before a blockage and packing of the system is initiated within the simulation;
 - Any subsea choke valve should have constant opening throughout the simulation and not be connected to any control functions within the simulation;
 - The hydrate blockage should be represented as a full bore valve that closes in 1 second;



- Since packing of the system can be very rapid in some cases, ensure that a small trend and profile plot interval is enabled within the simulation so that no pressure transients are missed and that the packing characteristics are captured in great detail; and
 - It is also advisable to use a small simulation integration time step as well as shorter pipe sections when constructing the model to ensure that the simulation does not miss any pressure transients.
7. Fortified Section Length Analysis/Optimization – The length of the fortified zone will be determined through the dynamic modeling by how far an upset can travel within the system before the safety valves have enough time to sense and isolate the low rated flowline section. In a sense, the fortified zone acts as an accumulator to withstand the pressure surge within the system until the inflow can be stopped.

To do this, a hydrate blockage should be placed at various distances along the flowline for each design case. This distance is essentially the proposed length of the fortified section. For each proposed length, the packing time between the HIPPS set point pressure and the MAOP of the downstream section at the blockage location is noted. These times can then be compared to the achievable HIPPS valve closure time. If the achievable closure time is less than the packing time, the fortified section is generally considered to be long enough. Settle out pressures should be checked however to confirm that the pressure does not rise unacceptably in the protected section of the line in the event of a blockage beyond the end of the fortified zone.

Since the design of the fortified section is heavily dependant on the valve closure time of the subsea HIPPS valves, attention must be paid to establishing what the achievable closure times are. Valve closure times are dependent on the valve diameter, bore pressure, water depth, valve orientation and rate of which the hydraulic fluid can be dumped. In addition HIPPS response times should also factor in sensor detection time (due to filtering, sampling etc) and a processing time for the controls system.

Design Examples of such an analysis are detailed in Section 5.2.2.5.

8. Additional Design Considerations:

- Pressure Surge/Water hammer – If a low GOR or high water cut fluid undergoes a HIPPS trip, due to the rapid closure times of the HIPPS valves there may be a pressure spike associated with the water hammer phenomenon. This pressure spike will be experienced upstream of the fortified section but any design of such a



HIPPS should check that the magnitude of any pressure spike does not exceed the design pressures of the upstream section.

Usually a quick first pass analysis can be provided by the Joukowsky equation detailed below, which should provide a preliminary conservative estimate of the likely pressure surge. If however the magnitude of the pressure surge is critical a more detailed analysis using a dynamic simulator should be considered.

$$\Delta P = \rho a \Delta V \quad (\text{Joukowsky Equation})$$

Where ΔP = The pressure rise associated with the waterhammer (Pa)

ρ = Fluid Density (kg/m^3)

ΔV = Change in fluid velocity on valve closure (m/s)

a = Speed of sound in fluid (m/s) (Pressure Wave Velocity)

$$a = \sqrt{\frac{\beta / \rho}{1 + (\kappa / E)(D / b)}}$$

Where β = Fluid Bulk Modulus (Pa)

E = Youngs Modulus of Pipe Wall (Pa)

D = Pipe Internal Diameter (m)

b = Pipe Wall Thickness (m)

- Low Temperature – Since the employment of a HIPPS entails a high pressure well, this creates the potential for low temperature excursions during start up operations, especially for gas wells. As the fortified section is of higher pressure rating (thicker pipe wall) this may entail more stringent low temperature (Sharpe) testing requirements, which may effect materials selection. Therefore a detailed analysis of start up scenarios with emphasis paid to low temperatures downstream of the subsea choke and HIPPS are required. Analysis will include not only the magnitude of any low temperature excursions but also the length along the flowline they extend during the start up operation.

5.2.2.5 Design Example

The following design example is for illustrative purposes only to show the trade off in valve closure times and fortified section length for a typical multiphase system. In this example, the MAOP of the flowline section downstream of the fortified section is 10,000 psia but the system shut in pressure for this case is 12,500 psia in early field life. The MAOP of the fortified section in all the design examples is assumed to be above the maximum wellhead shut in pressure.



Note – Figure 5-2 shows that there is a small transient offset pressure on top of the final shut in pressure for this case. This is caused by fluid settle out during the system packing. This specific case deals with a multiphase fluid whereas in practice the fortified section will be designed to a maximum well shut in pressure which is normally based on a gas only fluid column in the wellbore. This will give a shut in pressure in excess of the 12,500 psia shown in this design example.

The analysis will look in process sensitivities that effect the required closure time and what design cases should be considered. The sensitivities considered are:

- Fortified Length;
- HIPPS trip pressure setting;
- Flowrate; and
- Field Life.

Fortified Section Length

For this example the HIPPS trip pressure will be set at 8,000 psia, which gives a reasonable packing margin and is well above the FWHP of 3,000 psia.

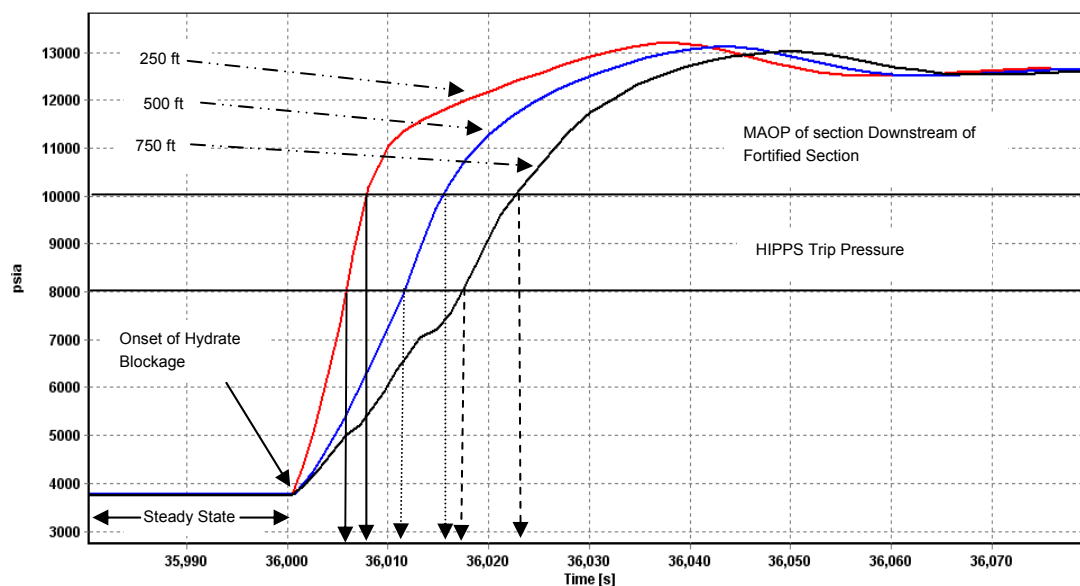


Figure 5-2 Pressure at Hydrate Blockage – Length Sensitivity

Figure 5-2 details the packing when a hydrate blockage occurs just downstream of the fortified section. A number of fortified section lengths are investigated to illustrate the required HIPPS valves closure times that will keep the non-fortified section, downstream of the HIPPS, from pressurizing above its MAOP.



Figure 5-2 shows that the hydrate blockage is initiated at time = 10 hours (36,000 sec) once the system has reached steady state. From this point on, the system upstream packs up to the shut in pressure at various rates depending on the length of the fortified section.

The required closure times (packing time between HIPPS set point and MAOP of downstream section) for each fortified section length are:

- 250 ft – 2 sec;
- 500 ft – 4 sec; and
- 750 ft – 6 sec.

The results for each fortified section length are then compared to the achievable HIPPS valves closure times to choose a suitable fortified section length. If, in this case, the achievable closure time is 4 s the fortified section should be at least 500 ft long, but to provide a healthy design margin the length should probably be 750 ft.

Figure 5-2 only highlights the method used to arrive at the required valve closure time. In so doing it allows the system to pack above the MAOP so as to detail a number of packing times for various cases. The effect of the HIPPS valve closure is not accounted for here, however Figures 5-3 and 5-4 show the system settle out pressure in the system when dealing with a 750 ft fortified section and a 6 second HIPPS valve closure time.

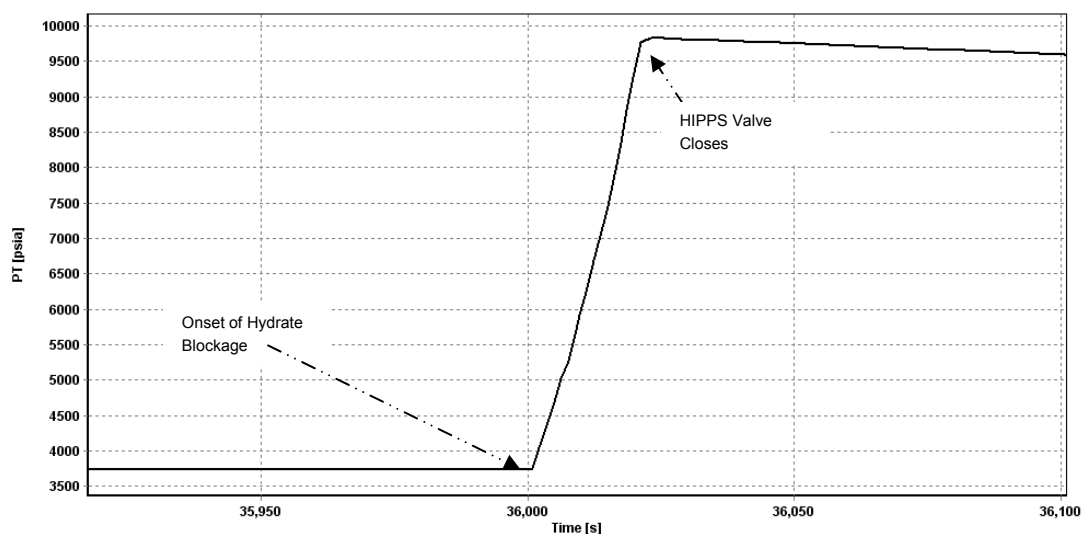


Figure 5-3 Pressure at Hydrate Blockage – 750ft Fortified Section with HIPPS Valve Closure at 6 s after 8000 psia Trip

Figure 5-3 shows that the system packs up to approximately 9800 psia. Here the peak pressure is slightly lower than 10,000 psia predicted in Figure 5-2, as the valve closure starts to restrict flow to the system as it begins to close where as Figure 5-2 continues to pack the system at the full rate thus predicting a conservative closure time of 6 seconds.

Figure 5-4 details the pressure profile for the system in the region of the fortified section after the HIPPS valve has closed. Downstream of the hydrate blockage the system is at low pressure similar to the steady state pressure. In the fortified section the pressure has settled out just below the MAOP and upstream of the HIPPS the system has shut in to wellhead shut in pressure.

The effect of the HIPPS valve closure shown above applies to the other design variables considered in this section.

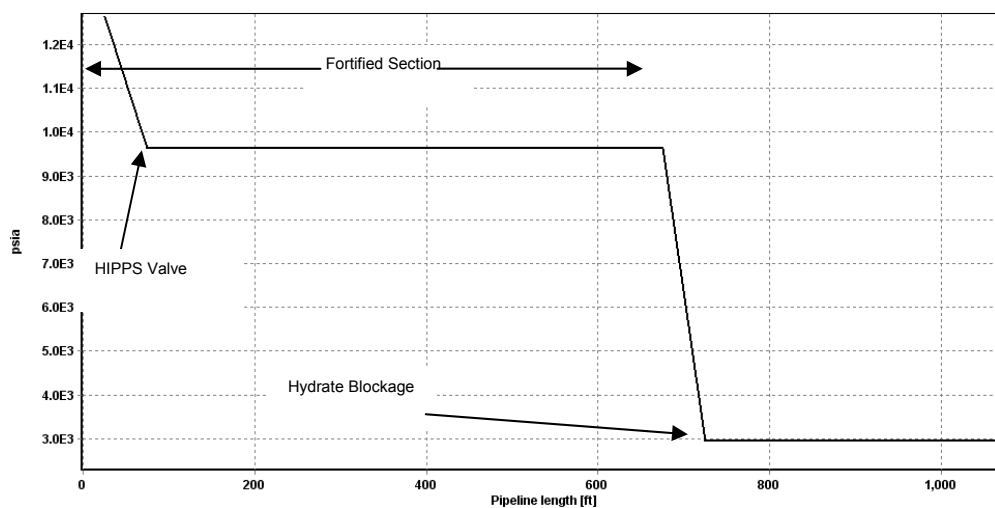


Figure 5-4 Pressure Profile – 750ft Fortified Section with HIPPS Valve Closure at 6 s after 8000 psia Trip

HIPPS Trip Pressure Setting

Figure 5-5 details the same case with a 750 ft fortified section but here the HIPPS trip pressure is varied.

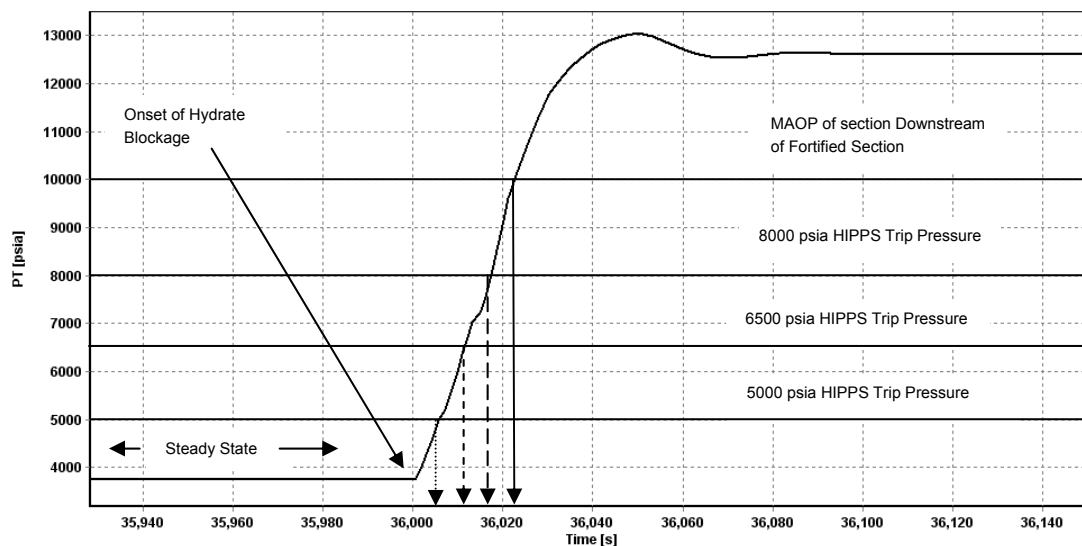


Figure 5-5 Pressure at Hydrate Blockage – HIPPS Trip Pressure Sensitivity
750 ft Fortified Section

The required closure times for HIPPS trip pressure set point are:



- 5000 psia – 18 sec;
- 6500 psia – 12 sec; and
- 8000 psia – 6 sec.

All of the trip set point pressures are well above the FWHP but by reducing the set point pressure the valve closure time can in this case be doubled or tripled. Some engineering judgment is required however as to where the trip pressure set point should be set so as to avoid lowering the set point to far and causing spurious trips caused during normal operation.

Flowrate

Figure 5-6 details the packing due to the variations in the flowrate prior to a hydrate blockage.

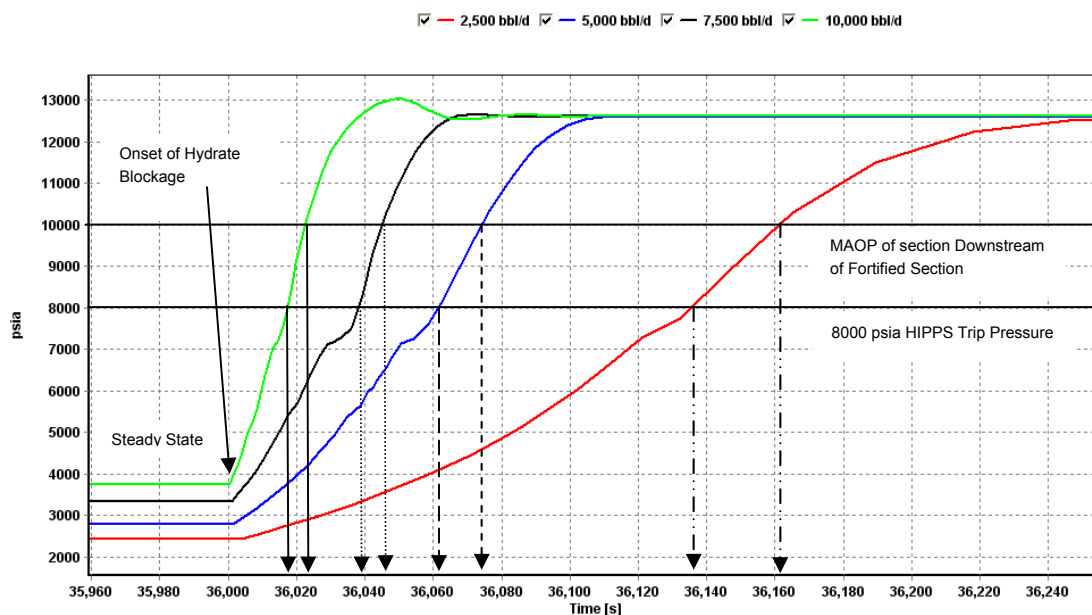


Figure 5-6 Pressure at Hydrate Blockage – Flowrate Sensitivity

750 ft Fortified Section

Figure 5-6 takes the same case detailed previously where the flowrate prior to blockage was 10,000 bbl/d and the fortified section is 750 ft long with a HIPPS pressure trip of 8000 psia. If the flowrate prior to blockage is reduced, Figure 5-6 shows that the required valve closure time increases significantly. This therefore highlights that any design case



considered should assume the maximum flowrate is present for that period in field life so as to capture the most conservative packing case.

Field Life

Figure 5-7 investigates the packing throughout field life. As expected the controlling case is early field life when reservoir pressure is high, flowrates are high and water cuts are low. As field life progresses the reservoir pressure declines, the flowrates and therefore the packing rate declines, as does the final shut in pressure (due to increased water cut therefore greater static pressure loss in the wellbore).

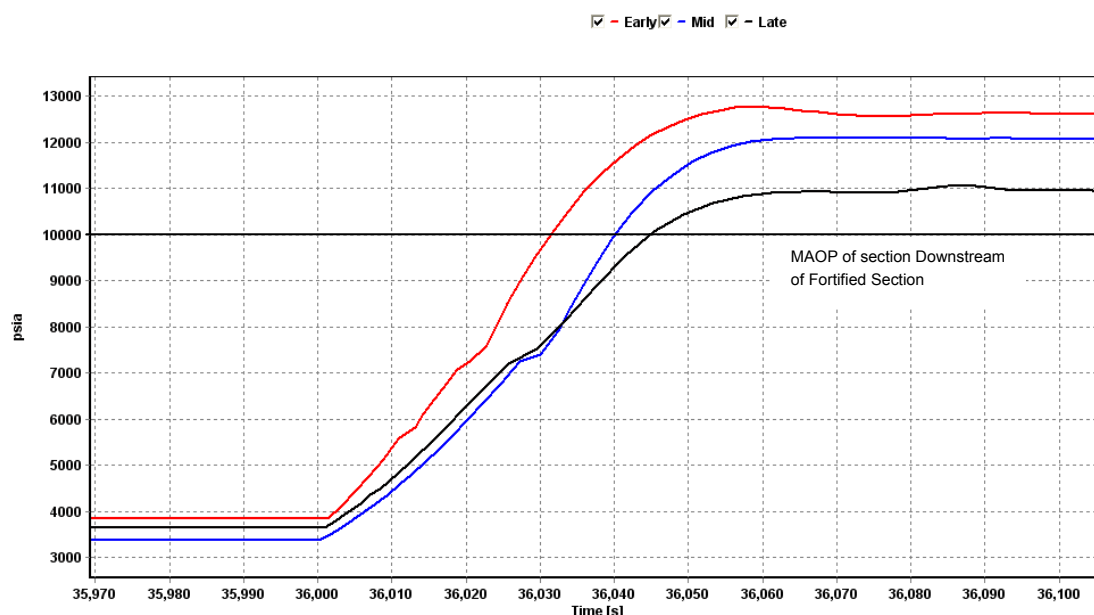


Figure 5-7 Pressure at Hydrate Blockage – Field Life Sensitivity

750 ft Fortified Section

If however the reservoir pressure maintenance is present, there may be the potential for conditions during later field life when there is more liquid pressure present that have a lower flowing wellhead pressure but a faster rate of packing as shown in Figure 5-8. Therefore a thorough analysis of all the design cases throughout field life is required so as to not miss the controlling packing case.

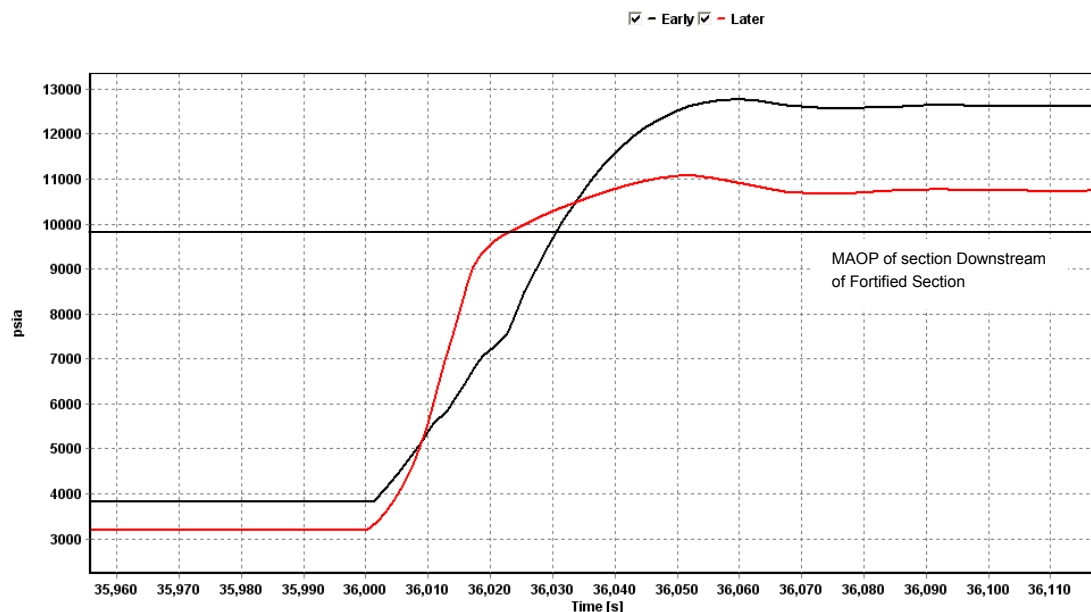


Figure 5-8 Pressure at Hydrate Blockage – Field Life Sensitivity with Pressure Maintenance – 750 ft Fortified Section

Safety Margin

The examples and sensitivity variables investigated are for the purposes of illustrating the design process that is required for the fortified section. Throughout the analysis the methodology of allowing the system to pack at full rate to and above the defined MAOP gives an inherently conservative HIPPS valve closure time which in combination with conservative assumptions for the other variables discussed, should provide an adequate safety factor to the design of the fortified section. However a detailed analysis is required to validate this.

5.2.3 Description of Fortified Section Testing

The fortified section of the flowline design relies on structural strength to hold the MAOP of the section which will be up to the Wellhead Shut-In Pressure (WHSIP). The testing required is the hydrostatic pressure testing per the applicable standards and will be higher for this section than for the protected sections.

Testing of the fortified section will thus require temporary isolation of the fortified section from the protected flowline such as by an inline valve or removable jumper.



6. TASK 600 – HIPPS FLOWLINE VERSUS RISER BURST IN DEEPWATER

6.1 Introduction & Summary

Take a 14.00" x 0.80" grade X-65 gas pipeline in 10,000 foot water depth with the design controlled by collapse when the pipe is empty. At this water depth the pipeline would have a Maximum Allowable Operating Pressure (MAOP) of approximately 10,000 psi. A riser for a well with this shut in pressure would require a wall thickness of approximately 1.4 inches to withstand the pressure at the top. This would be very difficult to weld and, given a single wall thickness throughout, require over a 1,200 kips of lay tension for the empty pipe (or 1,650 kips to hold flooded, as is often required). This tension is available from only a few of the largest vessels.

Now assume the well shut in pressure is going to be slightly above 10,000 psi but pressure during operation is going to be at or below an MAOP of 5,000 psi. Assume further that a HIPPS is proposed to protect the pipeline and riser from overpressure and that the riser is further fortified using the least conservative of the two fortification factors assumed in this study. A wall thickness of 1.3 inches might still be required. This enables the pipeline segment, even with 10,000 feet of external head, to protect the riser in the event that the HIPPS fails, since the unfortified pipeline will not be as resistant as the riser to burst. However, the riser still requires a lay tension above 1,000 kips empty and even more flooded.

If the pipeline and riser could instead be designed to operate at 5,000 psi, using only a HIPPS for protection against the higher source pressure, the 0.80" wall thickness would be adequate everywhere. (Actually, at the weakest point at the top of the riser and using the riser design factor, the MAOP would be even greater than 5,000 psi but this study is based on 5,000 psi rating steps.)

This wall thickness would be below the 1.25 inch "post weld heat treatment" wall thickness and would drop the lay tension requirements to less than 500 kips for the empty riser (less than 1,000 kips flooded). The riser design would be more practical, considerable load would be removed from the floating production facility, and material costs would be reduced on the order of \$750,000 at current steel prices (\$2,000/ton assumed) vs. the fully rated riser. (Material costs would be reduced by \$600,000 compared to the fortified riser.)

This study shows that the issue illustrated above is most applicable at water depths in the 5,000 to 10,000 foot range and for larger pipe on the order of 14 to 22 inches in diameter.



There are a large number of possible parameter combinations. Using the figures in this study it is possible to assess them in the above manner. Information required to examine a case consists of:

- Source (or shut-in) pressure;
- MAOP of HIPPS protected pipeline and riser;
- Diameter of HIPPS protected pipeline and riser; and
- Water depth ranges for HIPPS protected pipeline and riser.

Example cases have been tabulated in Section 6.3.2 for a range of water depths from about 3,000 to 16,000 feet for a 10K source pressure at a wellhead on the seabed and a 5K HIPPS protected system with varying degrees of fortification.

Graphs have also been presented showing pipe diameter limits for a selected maximum pipelay tension and a maximum wall thickness.

Due to the large number of possible combinations of all the variables, the cases presented are not comprehensive, although intended to be among the more likely and useful.

Varying requirements for fortification are discussed in Section 6.2.

6.1.1 Objective and Purpose

As a safety measure in the event of a HIPPS failure, the MMS currently mandates that a HIPPS protected riser be more resistant to burst than its corresponding protected pipeline. Current design codes for pipeline and riser systems capable of withstanding full pressure call for a higher safety factor for the riser. The result of these codes is that, for shallow and moderate water depth optimized systems, should the system be over pressured, the pipeline would fail first meeting the MMS criteria. This limits consequences to economic and environmental damage rather than injury to personnel.

As water depths get deeper, however, the effect of external pressure becomes more pronounced. Before the pipeline can burst it must overcome the external water pressure. In addition the pipeline must be strong enough to resist collapse due to external water pressure when empty and may not be burst controlled. These effects can offset the relative difference in pipeline and riser code burst safety factors. They effectively strengthen the pipeline on the seabed against burst. This is not the case at the top of the riser where there is no external water pressure.



Another problem occurs in the case of a pipe-in-pipe (PIP) flowline and riser. While the internal pipeline will fail before the riser some designs could allow the pressure to migrate along the annulus, eventually reaching the top of the riser where the external pipeline has no pressure and would be most expected to fail.

The study examines a range of non-pipe-in-pipe designs to develop an envelope of conditions where meeting the criteria for pipeline failure before riser failure could be difficult with a HIPPS. The study is based on conventional design parameters such as a pipe grade of X-65, wall thicknesses below 1.25", and readily available installation tensions (1,000 kips is proposed although some exceptional vessels have more.) The study includes the affect of variation in gas product density with pressure.

For pipe-in-pipe the study identifies means to ensure the pipeline is weaker than the riser.

The study also explores the feasibility of providing relief mechanisms to ensure failure of the system away from the riser in the event the pipeline can not be designed to meet the required criteria.

6.1.2 Problem Statement

Under certain combinations of pressure differential, water depth, and pipe diameter it may be impractical to make the riser stronger than the pipeline.

The limits, resulting from the requirement that the pipeline/flowline protect the riser in the event of an overpressure condition, are investigated due to the effects of:

- Variability in the manufacture of the line pipe (grade, wall thickness, etc.);
- Lay tension/riser tension limits; and
- Increasing water depth and pressure containment requirements.

6.1.3 Scope

- Develop an envelope of parameters that illustrates where such cases may occur for anticipated Gulf of Mexico developments and present in graphical form;
- Explain the results and explore ancillary issues such as limitations on available riser installation capability and pipe availability; and
- Examine alternate solutions to providing safety in the system and discuss considerations in setting a safety criterion such as statistical variation in design parameters and the consequences of failure.



The study examines a range of significant variables:

- Nominal pipe sizes of 6", 10", 14", 18", and 22";
- Water depths from 1,000 to 16,000 feet; and
- Equipment pressure ratings of 5,000 psig, 10,000 psig, and 15,000 psig.

These values are representative of current and likely future gas production systems.

Granherne did not check whether the range of water depths and diameters examined would result in any case exceeding the combined stress capability of the riser in tension or any other limit states other than burst and collapse.

6.1.4 Methodology

The study is based on conventional design parameters such as a pipe grade of X-65 and API RP 1111 design criteria.

Gas is selected for the pipeline product because the pipe wall thickness is a function of the difference between internal and external pressure. A pipeline with high salt water cut for example would be much less constrained by the pipeline before riser burst criteria assuming it could be laid flooded.

The study includes the affect of variation in gas product density with pressure. Both a multi-component natural gas and pure methane were analyzed using industry standard software, PVTsim and Hysis. Good agreement was obtained between these packages and online data from <http://www.petrospec-technologies.com/resource/rhogcalc.htm> which was also the source of the multi-component gas assumed for the exercise.

Figure 6-1 shows the resulting pressure vs. density results. It can be seen that multi-component gas is denser. While realistic this would result in lower pressures at the top of the riser than if pure methane is assumed. Methane was used for this study in order to be conservative, the composition of multi-component gas being variable from field to field.

In addition a log formula, as shown in the figure, was fit to the data using Excel in order to calculate density values for use in the study.

The Interaction Diagrams developed in the study were calculated simply by plotting a large number of cases. An in-house API RP 1111 based design tool was used for this purpose and results checked against ASME B31 algorithms.

No corrosion allowance is considered and wall thicknesses are not constrained to standard values.

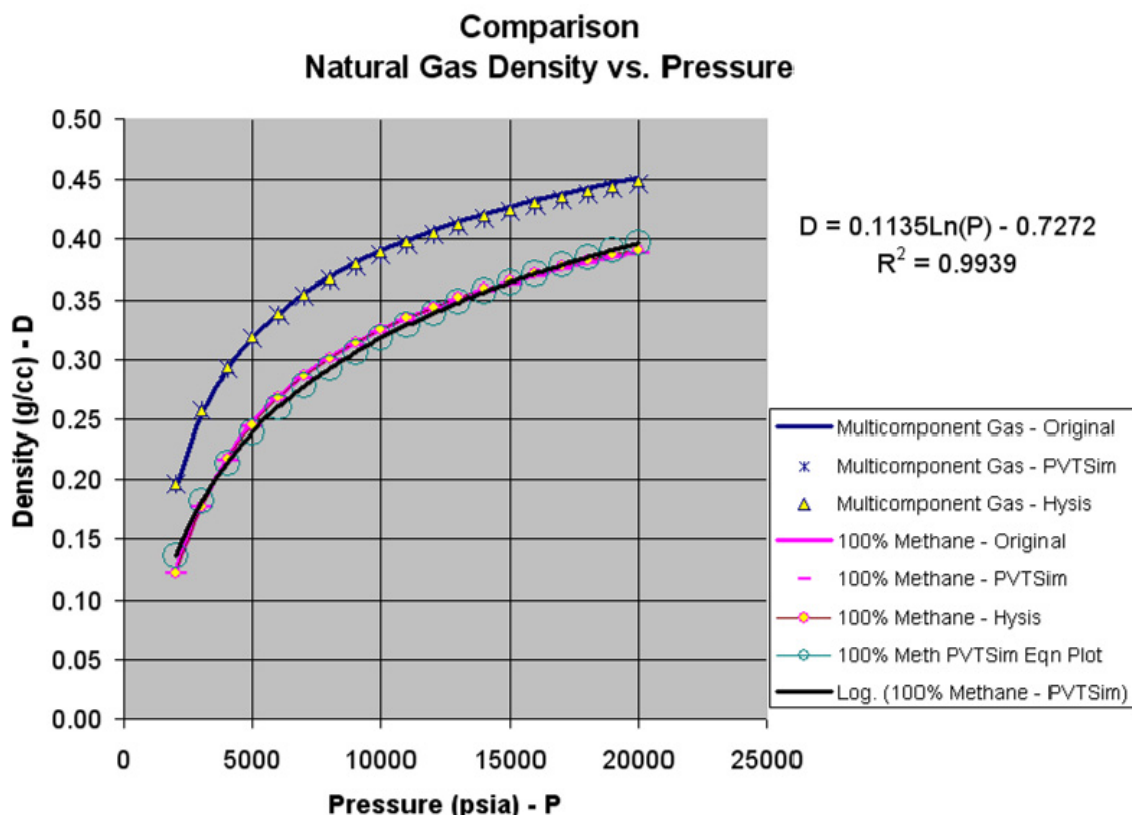


Figure 6-1 Natural Gas Density vs. Pressure for Methane and Multi-component Gas

6.2 Riser vs. Flowline Strength Margin

6.2.1 Fortification Factor

Section 4.1.5 of API RP 170, Recommended Practice for Subsea High Integrity Pressure Protection Systems (HIPPS), reads:

The near-platform riser section should be designed such that release of hydrocarbon or hazardous materials occurs away from the facility to protect personnel. Near-platform riser section refers to a region, which if breached by high pressure excursions, could result in damage to the facility or threat to life.

No specific guidance is given on how to accomplish such a design. However, this would generally be done by designing the near-platform riser section to a more conservative factor than the more remote sections of the pipeline system.

For this study a maximum fortification factor on the order of 20% is suggested based on analogy to current non-HIPPS practice for a wet insulated or non-insulated pipe (i.e., API RP 1111 design factors of 0.6 for riser and 0.72 for flowlines as illustrated in Figure 6-2).



Stating this another way the net burst pressure for the riser, at its least burst resistant location, would be approximately 20% greater than for the pipeline at its least burst resistant location, considering the effects of internal and external pressure head. In the development of the “one size fits all” fortification curves described in Section 6.3.1 the additional consideration of consistent transitions between controlling design parameters is addressed. These curves have been developed for the purposes of this study and the examination of sensitivities rather than to suggest such a factor for design and do contain some approximations. Subsequent to the original work the MMS requested further discussion of possible fortification factors and, based on the findings of the study, this has been done in Section 6.2.2.

The conventional case for a fully rated conventional pipeline with negligible elevation differences and no external head is illustrated below.

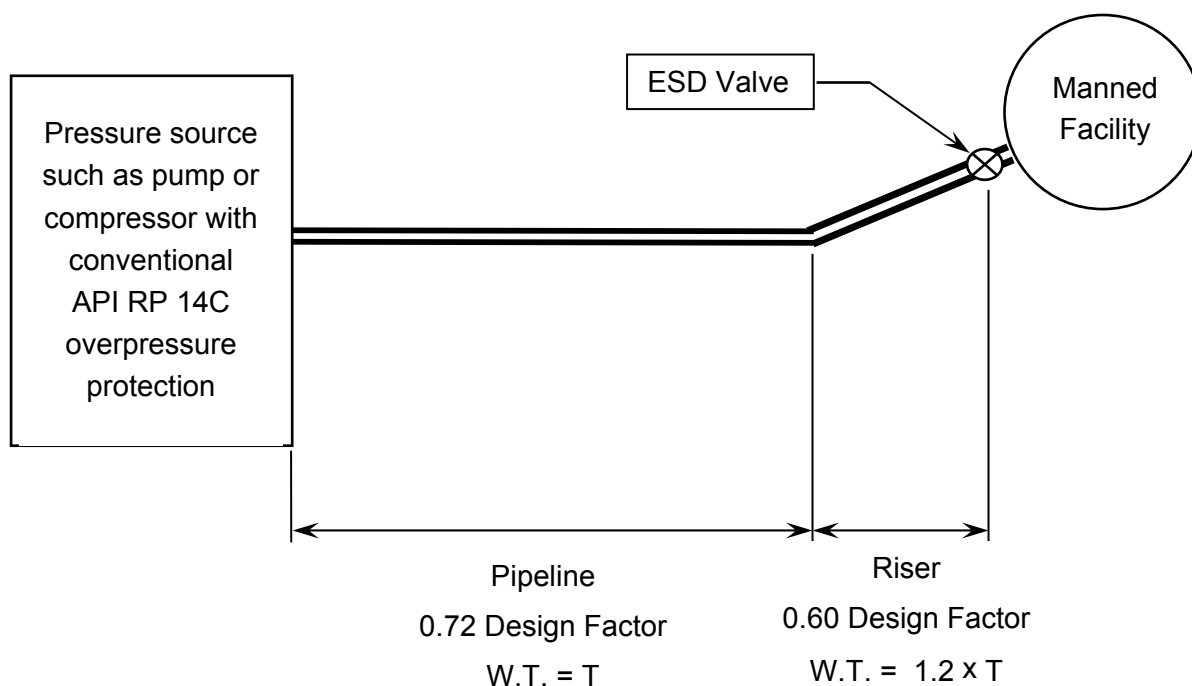


Figure 6-2 Conventional Design

Note Figure 6-2 assumes the pipe design has been economically optimized for both the pipeline and riser. It is not mandatory for the pipeline to be thinner than the riser in conventional practice but such a design would not be uncommon.

For the purposes of designing a HIPPS protected pipeline and riser what issues does this factor address?



The most significant concern is the statistical variation in pipe properties and the resulting variation in strength. For example it is possible for a piece of pipe in the riser section to be at the minimum wall thickness tolerance while the pipe in the pipeline section has greater than nominal thickness. Furthermore pipe in the riser could just meet the SMYS while pipe in the flowline, although to the same grade, could be stronger.

Wall thickness tolerances for Product Specification Level (PSL) 2 pipe ordered for offshore service are given in Table J4 of API Specification 5L as shown in Figure 6-3.

For seamless pipe less than 14 inch nominal diameter and between 0.394 and 0.984 inch wall thickness, the wall thickness tolerance is $\pm 12.5\%$ corresponding to approximately 25% variation from thinnest to thickest. For welded pipe the variation is not a constant percent but a fixed value for thicknesses in a given range. For example, for a pipe wall thickness of 0.615 inch the tolerance would be ± 0.039 inches corresponding to approximately 13% variation.



Table J.4 — Tolerances for wall thickness

| Wall thickness t mm (in) | Tolerances ^a mm (in) |
|--|--|
| SMLS pipe | |
| $< 4,0$ (0.157) | + 0,6 (0.024) – 0,5 (0.020) |
| $\geq 4,0$ (0.157) to $< 10,0$ (0.394) | + 0,15 t – 0,125 t |
| $\geq 10,0$ (0.394) to $< 25,0$ (0.984) | + 0,125 t – 0,125 t |
| $\geq 25,0$ (0.984) | + 3,7 (0.146) or + 0,1 t , whichever is the greater ^b – 3,0 (0.120) or – 0,1 t , whichever is the greater ^b |
| HFW pipe ^{c,d} | |
| $\leq 6,0$ (0.236) | $\pm 0,4$ (0.016) |
| $> 6,0$ (0.236) to $\leq 15,0$ (0.591) | $\pm 0,7$ (0.028) |
| $> 15,0$ (0.591) | $\pm 1,0$ (0.039) |
| SAW pipe ^{c,d} | |
| $\leq 6,0$ (0.236) | $\pm 0,5$ (0.020) |
| $> 6,0$ (0.236) to $\leq 10,0$ (0.394) | $\pm 0,7$ (0.028) |
| $> 10,0$ (0.394) to $\leq 20,0$ (0.787) | $\pm 1,0$ (0.039) |
| $> 20,0$ (0.787) | + 1,5 (0.060) – 1,0 (0.039) |
| ^a If the purchase order specifies a minus tolerance for wall thickness smaller than the applicable value given in this table, the plus tolerance for wall thickness shall be increased by an amount sufficient to maintain the applicable tolerance range. ^b For pipe with $D \geq 355,6$ mm (14.000 in) and $t \geq 25,0$ mm (0.984 in) the tolerance is $\begin{matrix} +12,5\% \\ -12,5\% \end{matrix}$. ^c The plus tolerance for wall thickness does not apply to the weld area. ^d See 9.13.2 and J.7.2 for additional restrictions. | |

Figure 6-3 Table J4 of API Specification 5L

The maximum variation in pipe material strength from API Specification 5L for PSL 2 pipe is given in Figure 6-4 below. For a common offshore grade like X-65 the minimum strength is 65,300 psi while the maximum is 77,600 psi for a variation of 19%. Lower grades such as X56 and X60 have approximately 25% allowable variation.



Table 6 — Requirements for the results of tensile tests for PSL 1 pipe

| Pipe grade | Pipe body of seamless and welded pipes | | | Weld seam of EW, SAW and COW pipes |
|------------------------------|---|--|-------------------------------------|--|
| | Yield strength ^a $R_{t0.5}$ MPa (psi) minimum | Tensile strength ^a R_m MPa (psi) minimum | Elongation A_f % minimum | Tensile strength ^b R_m MPa (psi) minimum |
| L175 or A25 | 175 (25 400) | 310 (45 000) | c | 310 (45 000) |
| L175P or A25P | 175 (25 400) | 310 (45 000) | c | 310 (45 000) |
| L210 or A | 210 (30 500) | 335 (48 600) | c | 335 (48 600) |
| L245R or BR L245 or B | 245 (35 500) | 415 (60 200) | c | 415 (60 200) |
| L290R or X42R L290 or X42 | 290 (42 100) | 415 (60 200) | c | 415 (60 200) |
| L320 or X46 | 320 (46 400) | 435 (63 100) | c | 435 (63 100) |
| L360 or X52 | 360 (52 200) | 460 (66 700) | c | 460 (66 700) |
| L390 or X56 | 390 (56 600) | 490 (71 100) | c | 490 (71 100) |
| L415 or X60 | 415 (60 200) | 520 (75 400) | c | 520 (75 400) |
| L450 or X65 | 450 (65 300) | 535 (77 600) | c | 535 (77 600) |
| L485 or X70 | 485 (70 300) | 570 (82 700) | c | 570 (82 700) |

^a For intermediate grades, the difference between the specified minimum tensile strength and the specified minimum yield strength for the pipe body shall be as given in the table for the next higher grade.

^b For intermediate grades, the specified minimum tensile strength for the weld seam shall be the same value as was determined for the pipe body using footnote a).

^c The specified minimum elongation, A_f , expressed in percent and rounded to the nearest percent, shall be as determined using the following equation:

$$A_f = C \frac{A_{xc}^{0.2}}{U^{0.9}}$$

where

C is 1 940 for calculations using SI units and 625 000 for calculations using USC units;

A_{xc} is the applicable tensile test piece cross-sectional area, expressed in square millimetres (square inches), as follows:

- for circular cross-section test pieces, 130 mm² (0.20 in²) for 12,5 mm (0.500 in) and 8,9 mm (0.350 in) diameter test pieces; and 65 mm² (0.10 in²) for 6,4 mm (0.250 in) diameter test pieces;
- for full-section test pieces, the lesser of a) 485 mm² (0.75 in²) and b) the cross-sectional area of the test piece, derived using the specified outside diameter and the specified wall thickness of the pipe, rounded to the nearest 10 mm² (0.01 in²);
- for strip test pieces, the lesser of a) 485 mm² (0.75 in²) and b) the cross-sectional area of the test piece, derived using the specified width of the test piece and the specified wall thickness of the pipe, rounded to the nearest 10 mm² (0.01 in²);

U is the specified minimum tensile strength, expressed in megapascals (pounds per square inch).

Figure 6-4 Table 6 of API Specification 5L



An extreme variation determined from the above tables for X60, 14 inch seamless pipe would be close to 50%. However, this would require that all the pipe in the pipeline be of the maximum allowable material strength and thickness and that at least one place near the top of the riser be of minimum thickness and strength. The chance of this being the case is negligible.

At the other, equally unlikely, extreme the riser could end up with all the high yield, over tolerance pipe and the pipeline with none making the riser stronger than the pipeline even with no additional factor.

A statistical analysis would be one way to determine just what a reasonably safe combined variation is. This would vary for different types of pipe, grades, diameters, and wall thicknesses. In addition once elevation differences and differential heads are taken into account the probability of a given strength differential becomes even harder to define. Thus a pragmatic approach has been adopted for this work, based on customary factors as described rather than rigorous statistical analysis.

The designer also has some control over these statistical parameters by specifying more stringent manufacturing tolerances than required for standard pipe. This could reduce the uncertainty and potentially the degree of fortification required.

This study has also been based on the assumption of a gas flowline for which the issue is most critical. At the other extreme, for example, would be a pipeline with high brine water cut. Such a flowline, if designed to the minimum thickness requirements and with collapse not controlling, might be fortified with respect to the riser per normal design practice since internal head could cancel out external head. The same benefit would accrue to an oil system but to a lesser extent.

References:

- API RP 17O, Recommended Practice for Subsea High Integrity Pressure Protection Systems (HIPPS), API Balloting Draft of April 2009;
- API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, 7th Edition, 01-Mar-2001; and
- API SPECIFICATION 5L, Specification for Line Pipe, 44TH Edition, October 1, 2007 with addendum of February 2009.



6.2.2 Relative Safety Requirements

For this study the simplifying assumption, that the riser is uniform in diameter and wall thickness and thus weakest at the waterline, will be made along with the assumption that the pipeline is of the same diameter and weakest at its point of shallowest depth. It will also be assumed that the pipeline wall thickness is uniform over its entire length.

While the above approach is common practice to simplify the logistics of getting the right pipe installed in the right place, it is not mandatory. Varying these parameters along the pipeline and riser may give the designer some flexibility in meeting the fortification requirements.

Another factor that should be considered in determining how much fortification is required is that all HIPPS protected systems are not created equal.

By way of example, a HIPPS may be beneficial when the MAOP of the protected system falls just slightly below the source pressure. A HIPPS failure in such a system would not have the same consequences as where a large differential pressure exists between the source pressure and the protected systems capability.

It is possible to categorize several different ranges in this regards as indicated in Table 6-1.

Table 6-1 Relative Differential Pressure Categories

| Category | Maximum Source Pressure |
|----------|--|
| 1 | Maximum source pressure exceeds protected section MAOP but is less than the hydrotest pressure of the lowest tested component at the component's location. |
| 2 | Maximum source pressure exceeds Category 1 pressure but is less than the burst pressure of the weakest component at the component's location |
| 3 | Maximum source pressure exceeds Category 2 pressure. |

The degree of fortification is arguably less critical for a Category 1 system than for a Category 3 system.



Note that the burst pressure as defined per API RP 1111, Section 4.3.1 or Annex B, considers the tolerances discussed in Section 6.2.1 and additional safety margins and is thus less than the ultimate burst pressure of the pipe.

Another common situation is when the source pressure exceeds the MAOP of the protected system for only a short duration during the life of the system. The shut in pressure for a field with a 10 to 20 year design life may drop rapidly upon initial production and only exceed a HIPPS protected system's MAOP for a few years at the beginning of production.

On this basis an approach for determining an appropriate amount of fortification is suggested below. This of course can not anticipate all potential HIPPS usage situations and would need to be adapted or justified on a case by case basis. Fortification ranges along the lines of the following would result.

- Category 1; If the maximum source pressure is greater than riser MAOP and less than riser hydrostatic test pressure use fortification in the range of 1 – 50% of maximum.
- Category 2: If the maximum source pressure is between hydrostatic and burst pressure use fortification in the range of 51 – 90% of maximum.
- Category 3: If the maximum source pressure is greater than the burst pressure, use fortification in the range of 91 – 100% of maximum.

A degree of fortification, represented by the D/t curve in this report, to allow a consistent transition from the burst controlled riser design to the fortification controlled riser design, is proposed as the maximum amount of fortification. It would be formulated so that, no matter what the MAOP of the protected riser and pipeline, the transition from one D/t curve to another would occur with no step discontinuity at the water depth where the flowline design changes from burst controlled to collapse controlled.

This maximum degree of fortification is loosely based on maintaining the strength ratio between the riser and pipeline that would currently apply for a fully rated system in negligible water depth where both the pipeline and riser were designed exactly to their maximum allowable stresses. This is believed to be reasonable way to capture the maximum likely adverse variation in pipeline versus riser strength due to allowable tolerances in API 5L pipe. However, as noted above, a considerable amount of data and statistical effort might be required to demonstrate this.



A minimum degree of fortification would be established based on a second curve. This curve is based on pipe at the seabed and at the surface theoretically bursting at the exact same time in the event of sufficient overpressure.

Recognizing a range of potentially applicable fortification factors for each Category described above allows consideration of factors that reduce the risk in a given case.

Table 6-2 below symbolically summarizes fortification ranges proposed above. Narrower ranges apply to categories with higher risk. $(D/t)_{thk}$ is used to represent the strength obtained using the revised fortified riser D/t curve, developed as described in Figure 6-6 – i.e., thickest riser requirement. Likewise $(D/t)_{thn}$ is the ratio required to keep the pipe at the seabed equal in burst strength to the pipe at the surface. The suggested range of fortification, as a percentage of $\Delta(D/t)$ where $\Delta(D/t) = (D/t)_{thn} - (D/t)_{thk}$, is tabulated below. $\Delta(D/t)$ represents the maximum allowable decrease from $(D/t)_{thn}$. Figure 6-15 in Section 6.5.2 shows both $(D/t)_{thk}$ and $(D/t)_{thn}$ curves

Table 6-2 Fortification Factor Range vs. Risk Category

| Category | Range of Maximum Source Pressure, P_m | Degree of Fortification |
|----------|---|-------------------------|
| 1 | Riser MAOP < P_m ≤ Hydrotest Pressure | 1%-50% $\Delta(D/t)$ |
| 2 | Hydrotest Pressure < P_m < Burst Pressure | 51%-90% $\Delta(D/t)$ |
| 3 | P_m ≥ Burst Pressure | 91%-100% $\Delta(D/t)$ |

Note: All pressures taken at water line elevation at top of riser.

The following factors would influence the actual selection of a fortification factor from the applicable range.

- How close is P_m to the limits of the given range? A maximum of 100 psi over MAOP might permit a lower factor than one 100 psi under Hydrotest Pressure
- What is the HIPPS design life? A HIPPS that has undergone quarterly testing for 25 years would not be the same as a new HIPPS or the same as a regularly rebuilt HIPPS required to work for only a few years
- What is the likely failure no touch time? A HIPPS leaking into a system with the capability to automatically maintain pressure by bleeding off small volumes to a flare might have less risk than a HIPPS leaking into a system which is fully shut-in for a long unattended duration.



- What special provisions have been taken to reduce the risk of weak pipe in the riser? Technology exists to measure every joint of pipe in an order and segregate heavier wall pipe for the riser and thinner wall pipe for the flowline making tolerances work to reduce risk.
- Are the flowline and riser pipe specified to tighter tolerances than standard API requirements? Reducing uncertainty reduces the required degree of fortification.
- Does the HIPPS have an actual SIL greater than the minimum value of 3 that has been proposed for Gulf of Mexico subsea use? A SIL of 4 for example has a reduced chance of failure.
- What is the product in the riser? A product with less stored energy, such as oil, may allow a lesser degree of fortification than a system with a large stored volume of gas.

Note that, whatever the result of the riser fortification assessment, the riser and flowline must still, of course, also meet the requirements of the applicable codes with respect to the MAOP required for normal operation with the HIPPS in place. In other words the riser design must meet MAOP or fortification based on risk category, whichever is more stringent.

To graphically determine the wall thickness of a riser with respect to these ranges, go into Figure 6-15 with a known water depth and rating then:

1. Draw a horizontal line at the water depth, say 4000 feet.
2. Where this line crosses the flowline burst line for the rating (say 5000 psi FL burst line) draw a vertical line to get the D/t .
3. Do likewise as appropriate for the controlling values to determine the D/t values where the depth line crosses the collapse line, where it crosses the $(D/t)_{thn}$ line and where it crosses the $(D/t)_{thk}$ line.
4. Take the diameter and divide by the D/t 's to get the corresponding wall thicknesses. (The top of the riser has to be rated for MAOP or have a wall thickness corresponding to $(D/t)_{thn}$ (i.e., t_{thn}) whichever is greater.)
5. Divide the wall thickness difference between t_{thk} and t_{thn} into the three category ranges based on the indicated percentage intervals to identify the limiting thicknesses. Which Category range gets selected, when MAOP permits (at approximately 5000 ft depths or greater) depends on the shut-in pressure. Further refinement depends on the factors given above.



It should be noted that this study and the above discussion is predicated on the need for a protective segment of pipeline or other method to ensure a failure does not occur at the riser. However, the premise behind the design of a HIPPS is that it already provides a level of safety similar to a fully rated system. In addition the HIPPS does not act until a series of other failures in the normal control system and well safety isolation systems have taken place. A high degree of fortification may thus not be required.

It should also be noted that with time, HIPPS for deepwater applications should develop more of a track record and that this may allow the removal of conservativeness that is advisable at this time. It is certainly true that while the reliability of safety instrumented systems such as HIPPS are high they are a more complex solution than thicker steel and do rely on a longer chain of calculations and data to document this reliability.

6.3 Results

6.3.1 Interaction Diagram

The figures in this section illustrate the interaction of pipeline and riser collapse, pipeline and riser burst, and riser fortification for a wide range of cases. The graphs have been created for X-65 grade pipe, 5,000, 10,000 and 15,000 psig (5K, 10K & 15K) internal pressures, and 1,000 to 16,000 foot water depths. Contents have been assumed to be pure methane and the relationship between internal head, pressure, and density has been accounted for.

For maximum usefulness and consistency we have used API RP 1111 design formulas and design factors for “burst” and “collapse” curves. **When we refer to burst and collapse with respect to these curves we are not talking about the actual failure limits but the code limits after application of code design factors,** in other words the D/t values can be converted to actual design wall thicknesses. Conservatively no corrosion allowance has been assumed in the calculations. Use of a corrosion allowance will increase the wall thickness and pipe weights, magnifying the adverse effects of the riser fortification requirement.

The interaction diagram plots various curves for the non dimensional pipeline outer diameter to wall thickness ratio, D/t, against water depth in feet. The diagram puts shallow depths at the bottom with depths increasing toward the top and relatively thick wall pipe to the left and thin wall pipe to the right. This presentation format has been chosen to enable concise illustration of the interaction between the parameters. This is also a handy format for determining wall thickness given a pipe diameter, water depth; HIPPS protected section equipment rating, and fully rated section equipment rating.



Figure 6-5 shows two families of curves. One family of two curves, delineated by open circles every thousand feet of depth, trends from the upper left to the lower right. The rightmost of these (light blue) is the collapse depth of an empty pipe on the seabed. The leftmost of these (magenta) is a riser arbitrarily fortified to be stronger at the surface than the burst pressure of the pipeline at the seabed when the pipe wall thickness is governed by collapse. This case assumes that the pipeline and riser are protected from a pressure source higher than 5K by a HIPPS.

Recognize that the lines in Figure 6-5 are bounding limits but will not control at all depths as explained below. The lines have been extended across each other to show trends and define the crossing points where control changes from one design limit to another rather than being truncated in zones where they may not apply.

The second family of two curves, trending from lower left to upper right, is for a riser and pipeline fully rated to 5K burst respectively.

One further item is indicated by Figure 6-5. If we assume that pipe welding is more difficult for wall thicknesses over 1.25", for example due to a requirement for post weld heat treatment, we get two zones. These are shaded from green to yellow in the illustration. For high D/t pipe in the green zone post weld heat treatment is not required. Depending on diameter, as D/t's decrease below 16 or 17, special welding measures may be required. Fortification will put the large diameter risers in this zone in the 3,000 to 5,000 foot depth range. Without fortification such requirements will not occur for these risers until water depths exceed 11,000 feet.

A number of letter designated points are indicated for reference in the following discussion. A 14" pipeline will be used to illustrate the discussion in terms of actual diameters and wall thicknesses rather than the abstract non-dimensional D/t ratio. The use of buckle arrestors is assumed rather than the alternative of making the pipeline thick enough to resist propagation buckling.

The discussion will illustrate the controlling design parameters as the depth increases starting at a depth of 1,000 feet of seawater.

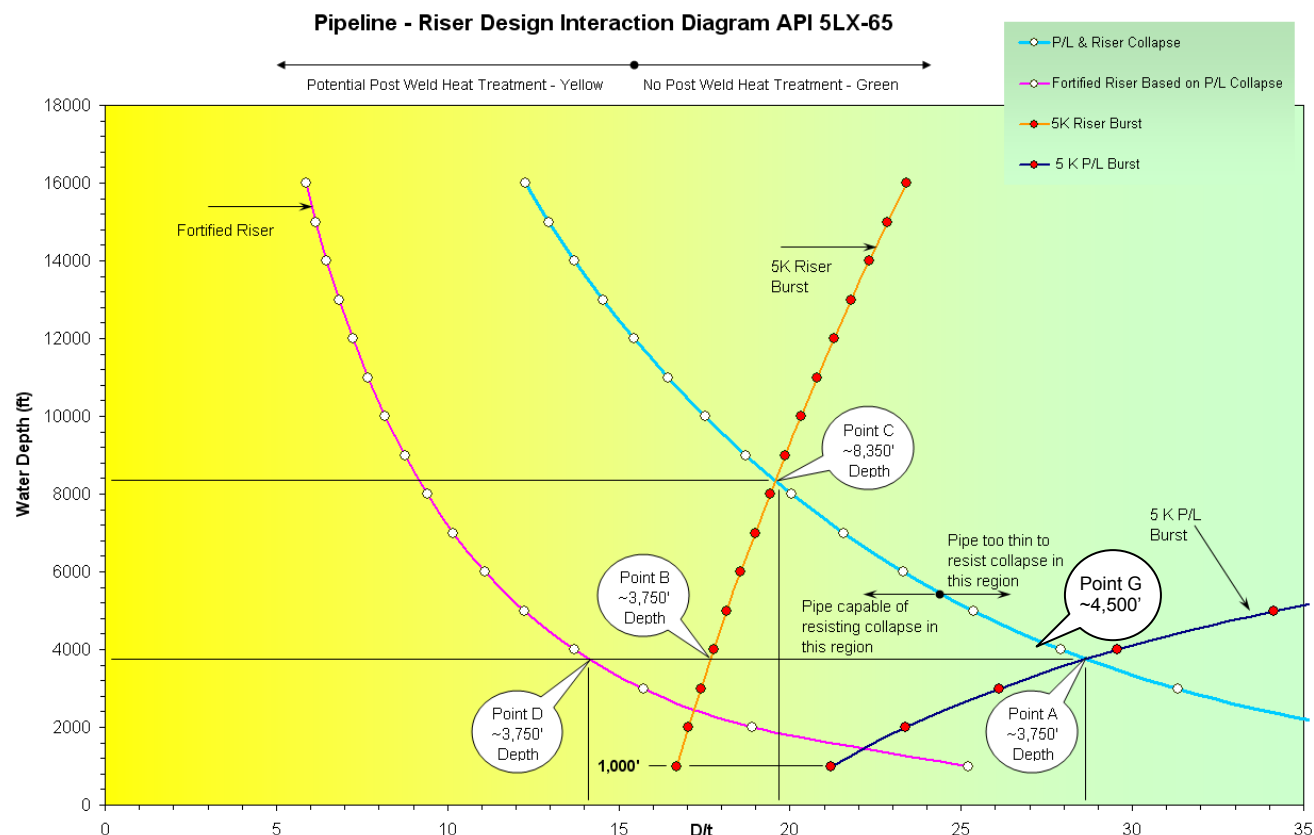


Figure 6-5 Interaction Diagram, 5K Protected System

As can be seen from Figure 6-5 at 1,000 foot water depth the pipeline has a D/t of 21.2 corresponding to a minimum 0.66 inch wall thickness for a 14 inch OD pipe. The wall thickness is much greater than required to prevent collapse, being far to the left of the light blue pipe collapse curve.

The riser D/t is 16.7 with a wall thickness of 0.84 inches for a 14 inch pipe.

Note that these values reflect a pressure of 5,000 psig in the pipeline on bottom and a corresponding external seawater head of 444 psig for a net pressure of 4,556 psig to be resisted by the pipe wall. The internal head of gas reduces the pressure inside the riser from 5,000 psig at the bottom of the riser to 4,891 psig at the waterline. Given no external pressure this is the point of highest net riser design pressure along the riser.

At this depth, with both pipeline and riser design governed by burst, as long as the pipeline is designed to the minimum wall thickness the riser is fortified by virtue of having a more conservative design factor. This would be a common design for a 5K non-HIPPS flowline and riser.



As the depth increases internal head in the riser increases leading to a reduction in required wall thickness for a constant OD. (This is the reason wells eventually stop flowing. Although there may be considerable pressure at the bottom of the hole it is not enough to lift all the contents above it.) It can be seen that the D/t of the riser at burst increases slowly with depth compared to that of the pipeline. This is because the external pressure gradient due to seawater is greater than the internal gradient due to gas. This situation continues to hold true until a depth of approximately 3,750 feet is reached.

At this point, labeled Point A in Figure 6-5, the pipeline becomes subject to collapse if laid empty or if it becomes empty. (If the line were to be laid flooded and kept full of water or oil during operation this limit would move.) Note that for the 14 inch pipeline, the minimum wall thickness has actually decreased from 0.66 to approximately 0.49 inches and the riser wall thickness has decreased from 0.84 to approximately 0.79 inches at Point B. Until this depth the relative strengths between the riser and the pipeline have been constant since both are designed against the same burst criterion. In the case of an overpressure event the pipeline, which has a less conservative design factor, would fail first protecting the riser.

If we continue to increase the water depth from Point A the pipeline wall thickness is governed by the requirement to prevent collapse and is thicker than required to prevent burst. In addition the wall thickness must now increase with depth rather than decrease since the added pressure no longer serves just to offset part of the internal pressure but directly drives the wall thickness. The riser remains burst governed with the effect that the riser strength and pipeline strength start to approach each other.

At about 8,350 foot depth (Point C) the pipeline and non-fortified riser are both at design limits and have the same wall thickness, however the pipeline is governed by collapse and the riser by burst. Thus, if pressurized to the burst limit state, the riser would fail before the pipeline. For a 14 inch pipe this corresponds to approximately a 0.71 inch wall thickness. As depths increase further, the riser and pipeline minimum thickness both remain on the collapse curve.

To keep the riser stronger than the pipeline it must instead be fortified starting at Point A, the point at which the pipeline is no longer governed by burst. This is the point at which relative margin in burst begins to decrease and where our arbitrarily assumed fortified curve, derived from the collapse curve, is assumed to start governing. (Note that a less arbitrary rationale is discussed later and a revised curve developed. This initial curve is retained to illustrate sensitivities but not otherwise recommended.)

The assumed fortified riser curve now governs in water depths greater than at Point A introducing a discontinuity as the riser wall thickness shifts from the burst curve to the



arbitrary fortified curve at Point D. For example our 14 inch riser wall thickness would jump from 0.79 inches to 0.99 inch with essentially no change in depth.

Removing the discontinuity requires changing the factor by the amount necessary to cause the fortified riser curve to intersect the burst curve at Point B, i.e., moving the fortified riser curve to the right. Point B is now on both the burst controlled riser and the fortified riser curves. This is illustrated in Figure 6-6. Non-controlling sections of other curves have also been de-emphasized in the figure.

In this example the revised fortified riser curve was moved to intersect the 5K riser burst curve at the depth where the pipeline 5K burst curve intersects the collapse curve. The fortified riser curve should also intersect the 10K riser burst curve at the depth where the pipeline 10K burst curve intersects the collapse curve and the 15K riser burst curve at the depth where the 15K pipeline burst curve intersects the collapse curve. Note that the revised fortified curve used in Figure 6-6 through Figure 6-13 and accompanying tables, as well as for the case studies was not generated this precisely. This leads to some discrepancies when used for higher pressure cases. A more accurate curve, generated to illustrate the range of potential fortification factors and for the reader's use, is shown in Figure 6-15 in Section 6.5.2.

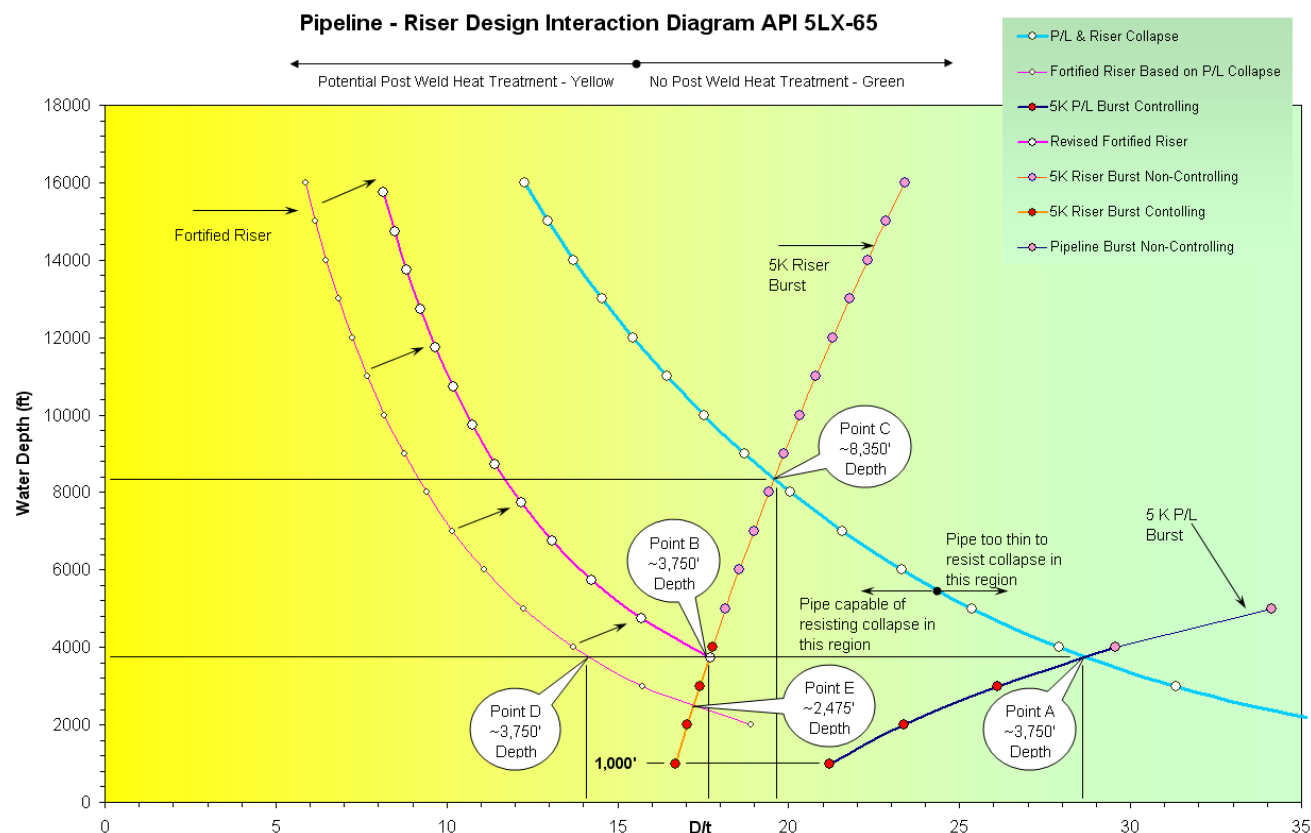


Figure 6-6 Interaction Diagram, Continuous Riser Design

Note that another more conservative, but less logically consistent approach, could be taken where the originally assumed or another conservative fortified curve is retained. How to transition without a discontinuity then needs to be addressed so that a large step jump in wall thickness does not occur the instant the pipeline switches from being governed by burst to being governed by collapse (e.g. for the 14 inch pipeline a change from 0.79 inch riser wall thickness at 3,749 foot depth to 0.99 inch wall thickness at 3,751 foot water depth). One approach would be to transition earlier at Point E in Figure 6-6 where the riser burst curve crosses the fortified riser curve. Transitioning at this point, while the pipeline and riser are both still governed by burst, to a curve calculated from pipeline collapse is somewhat arbitrary but does allow additional margin.

In Figure 6-7 an additional curve is drawn showing a burst criterion for a fully rated 10K riser. This illustrates that once an 11,000 foot water depth is reached at Point F the fortified riser is rated for 10,000 psig. At deeper depths the riser need not be fortified if wellhead shut in pressure without a HIPPS is less than 10,000 psi.

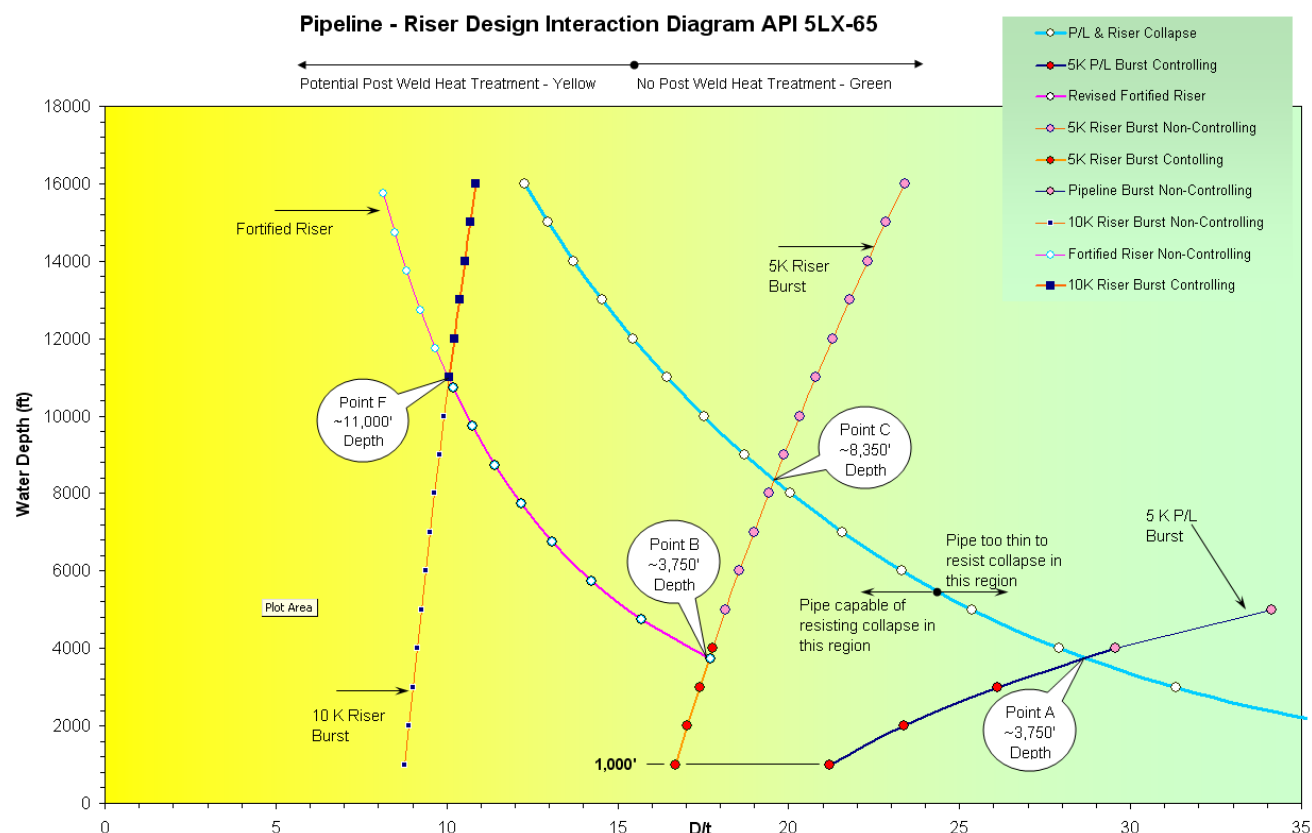


Figure 6-7 Interaction Diagram, 10K Riser

An illustration similar to Figure 6-7 could be made for other wellhead shut in pressures both above and below 10K.

Two combination curves are plotted to illustrate the design envelope for a 5K system that is protected from a higher pressure source using a HIPPS. One is for the fortified case just described, with a 10K pressure source (Figure 6-8) and the other is if no fortification is required and the HIPPS protection alone is considered adequate to protect the 5K riser (Figure 6-9).

These two curves serve to illustrate as a function of water depth:

- where fortification is not a governing factor,
- the effect of fortification, and
- where HIPPS is not beneficial for the given example.

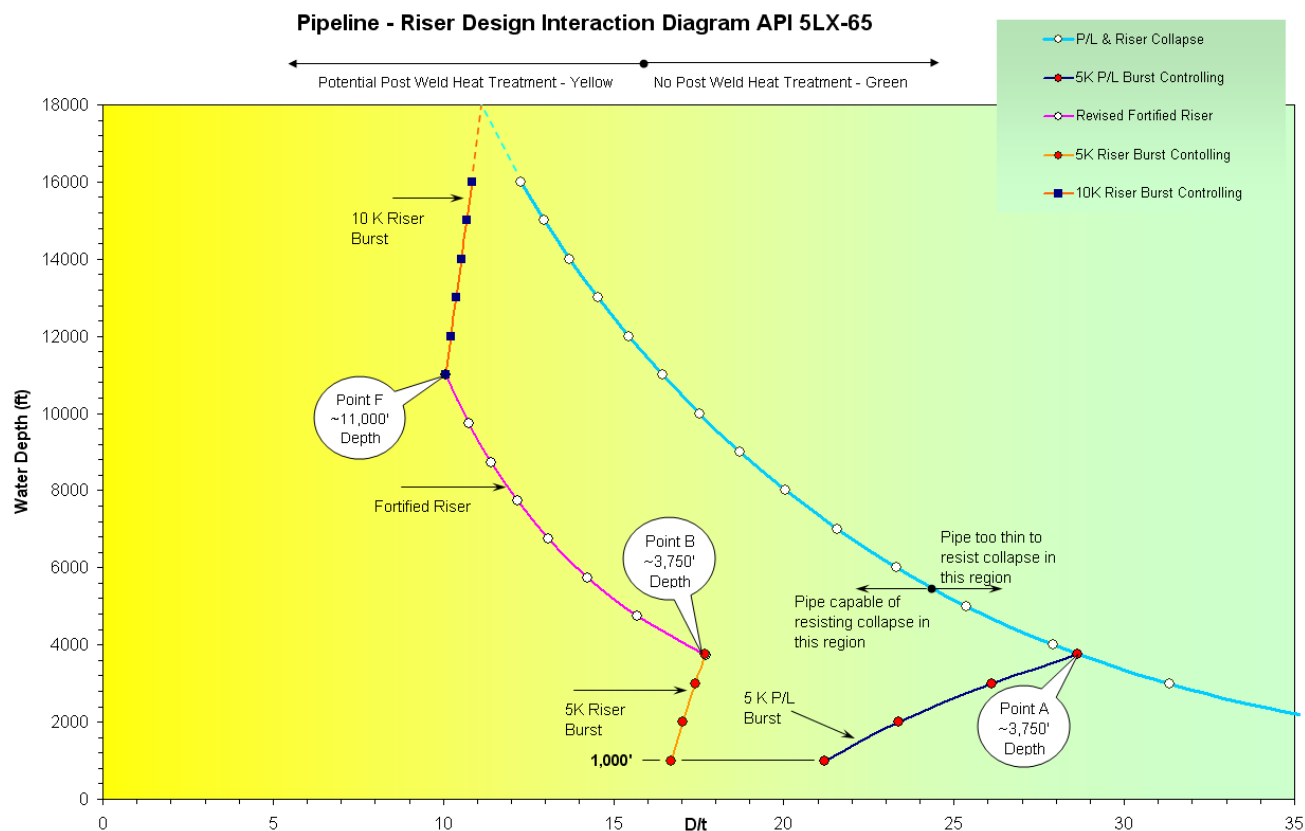


Figure 6-8 Fortified Riser

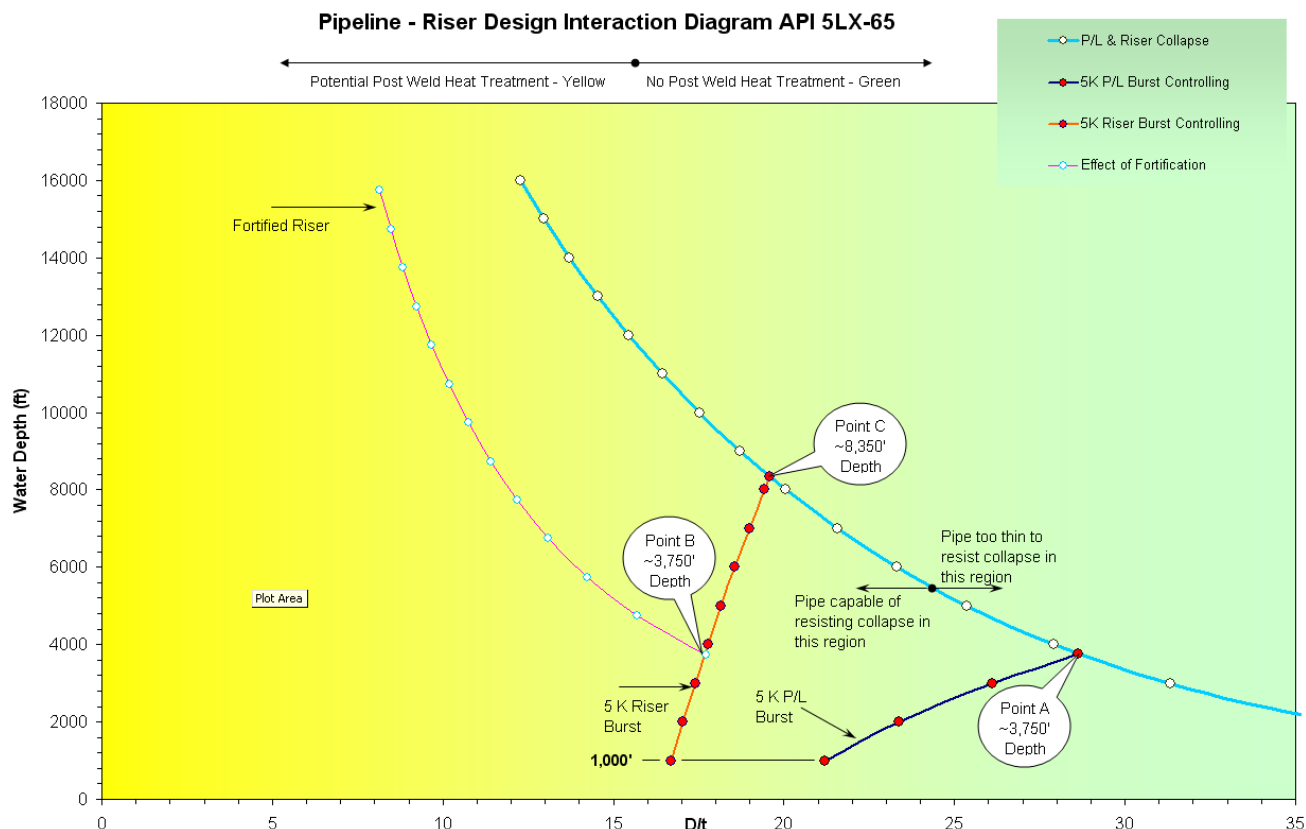


Figure 6-9 Un-Fortified Riser

The above figures are described below:

In Figure 6-8 the riser design at the shallower depths is governed by burst. As depths increase from 3,750 to 11,000 feet, riser fortification governs. At depths greater than 11,000 feet the riser is fully rated to resist the 10K wellhead shut in pressure and needs no HIPPS or fortification. Note that if depths increase as shown by the dashed extrapolations, somewhere around 18,000 feet pipe collapse would again be expected to govern the riser design if a constant wall thickness is maintained from top to bottom.

If the system is designed with a 5K non-fortified riser as shown in Figure 6-9, of uniform wall thickness from top to bottom, the internal riser pressure at the top would control the design at depths less than about 8,350 feet. At depths greater than this, the bottom of the riser will collapse unless the riser wall thickness is increased, so the riser design follows the pipeline collapse line.

Comparing the two design scenarios for the illustrated case shows that the fortification requirement has no impact on the design at depths less than 3,750 feet. From 3,750 foot water depth to 8,350 water depth the fortification would continually increase the riser wall



thickness required compared to a riser protected using the HIPPS alone, i.e., compared to a non-fortified riser. At depths greater than 8,350 feet the riser wall thickness required for fortification would remain consistently above that required for a riser protected using the HIPPS alone until a depth of 11,000 feet. At this point the fortified riser would be fully rated for 10,000 psig and as depth increased further neither fortification nor a HIPPS would be required.

Note that as shown in Figure 6-15 in Section 6.5.2, at 10,000 foot water depth the flowline would no longer require a HIPPS for protection but be fully rated.

It is estimated that at about 18,000 feet the riser would not be governed by burst but by collapse.

Figure 6-15 provides curves for the range of applicable cases covered in this study for use by the reader. While appearing complex, the Multi-Case Interaction Diagram can be used as described in the above simplified illustrations to determine details of pipe wall thickness for cases within the scope of the study.

Initially the intention was to carry the study up to 20K but, as can be seen in the figure, 15K is already extremely thick pipe for the assumed X-65 grade pipe. Use of a HIPPS, non-SCR type riser, and/or higher grade pipe will likely be necessary for such a high pressure riser in deep water. The riser fortification limitations are primarily dependent on the rating of the protected system as well, and the protected system is unlikely to be over 15K.

6.3.2 Typical Case Studies

The interaction diagrams can be used as described in the previous section to determine the sensitivity of a given scenario to the riser fortification requirement. Values have been extracted from the diagrams for a number of cases for comparisons to practical industry limitations.

Table 6-3 shows wall thicknesses for three pipe sizes and a 10K HIPPS protecting a 5K pipeline-riser system. The values are graphically based and are thus accurate to only two decimal places but still demonstrate the usefulness of the graphs for quick determination of wall thickness for a given set of assumptions. The table shows riser wall thicknesses if no fortification is required, if fortification is required, if the original, more conservative fortified curve which transitions at Point E in Figure 6-6 instead of Point B is used, and if riser is fully rated for various depths.

**Table 6-3 Effect of Fortification Requirements on Pipe Wall Thickness (inches)**

| Depth (ft) | Case | Pipeline OD | | |
|---------------|--|------------------|------------------|------------------|
| | | 6.625 (in) | 14 (in) | 22 (in) |
| 2,475 | 5K Pipeline | 0.27 | 0.57 | 0.9 |
| 2,475 | With HIPPS & No Riser Fortification (@ E) | 0.38 | 0.81 | 1.28 |
| 2,475 | With HIPPS & Point B Riser Fortification | N/A ¹ | N/A ¹ | N/A ¹ |
| 2,475 | With HIPPS & Point E Riser Fortification (@ E) | 0.38 | 0.81 | 1.28 |
| 2,475 | Fully rated 10K Riser | 0.74 | 1.56 | 2.46 |
| 3,750 | 5K Pipeline (@ A) | 0.23 | 0.49 | 0.77 |
| 3,750 | With HIPPS & No Riser Fortification (@ B) | 0.37 | 0.79 | 1.24 |
| 3,750 | With HIPPS & Point B Riser Fortification (@ B) | 0.37 | 0.79 | 1.24 |
| 3,750 | With HIPPS & Point E Riser Fortification (@ D) | 0.47 | 0.99 | 1.56 |
| 3,750 | Fully rated 10K Riser | 0.73 | 1.54 | 2.42 |
| 6,000 | 5K Pipeline (@ C) | 0.28 | 0.6 | 0.94 |
| 6,000 | With HIPPS & No Riser Fortification | 0.36 | 0.75 | 1.18 |
| 6,000 | With HIPPS & Point B Riser Fortification | 0.48 | 1.01 | 1.58 |
| 6,000 | With HIPPS & Point E Riser Fortification | 0.60 | 1.26 | 1.98 |
| 6,000 | Fully rated 10K Riser | 0.71 | 1.49 | 2.34 |
| 8,350 | 5K Pipeline (@ C) | 0.34 | 0.71 | 1.12 |
| 8,350 | With HIPPS & No Riser Fortification | 0.34 | 0.71 | 1.12 |
| 8,350 | With HIPPS & Point B Riser Fortification | 0.57 | 1.20 | 1.89 |
| 8,350 | With HIPPS & Point E Riser Fortification | N/A ² | N/A ² | N/A ² |
| 8,350 | Fully rated 10K Riser | 0.68 | 1.44 | 2.27 |



| Depth (ft) | Case | Pipeline OD | | |
|---------------|---|-------------------|-------------------|-------------------|
| | | 6.625 (in) | 14 (in) | 22 (in) |
| 11,000 | 5K Pipeline | 0.41 | 0.86 | 1.35 |
| 11,000 | With HIPPS & No Riser Fortification | 0.41 | 0.86 | 1.35 |
| 11,000 | With HIPPS & Point B Riser Fortification (@ F) | 0.66 ³ | 1.39 ³ | 2.18 ³ |
| 11,000 | With HIPPS & Point E Riser Fortification | N/A ² | N/A ² | N/A ² |
| 11,000 | Fully rated 10K Riser | 0.66 | 1.39 | 2.18 |
| 16,000 | 5K Pipeline | 0.54 | 1.14 | 1.79 |
| 16,000 | With HIPPS & No Riser Fortification | 0.54 | 1.14 | 1.79 |
| 16,000 | With HIPPS & Point B Riser Fortification | N/A ³ | N/A ³ | N/A ³ |
| 16,000 | With HIPPS & Point E Riser Fortification | N/A ² | N/A ² | N/A ² |
| 16,000 | Fully rated 10K Riser | 0.61 | 1.29 | 2.03 |
| 18,000 | 5K Pipeline <u>extrapolated</u> | 0.60 | 1.26 | 1.98 |
| 18,000 | With HIPPS & No Riser Fortification <u>extrapolated</u> | 0.60 | 1.26 | 1.98 |
| 18,000 | With HIPPS & Point B Riser Fortification | N/A ³ | N/A ³ | N/A ³ |
| 18,000 | With HIPPS & Point E Riser Fortification | N/A ² | N/A ² | N/A ² |
| 18,000 | Fully rated 10K Riser <u>extrapolated</u> | 0.60 | 1.26 | 1.98 |

Notes:

1. The 2,475 foot water depth is too shallow for the Point B Riser Fortification Curve to apply. The 5,000 psi burst rating controls both pipeline and riser design, i.e., collapse is not yet an issue. The Point B riser fortification assumption is that the riser is fortified with respect to the pipeline in shallow water if both are designed to their respective design factors to just meet burst requirements.



2. At 7,800 foot water depth the Point E Riser Fortification Curve would require a wall thickness equal to that required to resist full wellhead shut in pressure. At greater depths it would require a wall thickness greater than that required to resist full wellhead shut in pressure and is thus not applicable.
3. At 11,000 foot water depth the Point B Riser Fortification Curve requires a wall thickness equal to that required to resist full wellhead shut in pressure. At greater depths it would require a wall thickness greater than that required to resist full wellhead shut in pressure and is thus not applicable.

Table 6-3 illustrates how various assumptions, as to the degree of riser fortification, affect the wall thickness of the pipe. More difficult wall thicknesses to weld are shaded in yellow while thicknesses that are harder to procure are additionally shown in red text. Thicknesses in bold red text are considered beyond the current state of the art for production welding and could potentially face other difficulties such as a greater potential for brittle fracture.

For the tabulated scenario it can be seen that small diameter pipe is relatively insensitive to the fortification requirement. Likewise at shallower water depths the requirement is not onerous.

At the deepest depths, for the mere 10K shut-in pressure illustrated in the table the benefits of a HIPPS are minor and again the requirement for fortification is academic. With a 15 K or 20 K source pressure the riser burst line would move to the left in the Interaction Diagram and both the benefits of a HIPPS, the risks during a failure, and the limitations imposed by fortification would become greater.

It is in the intermediate depths, what we currently would call ultra-deep water from 5,000 to 10,000 foot water depths, that the requirement for fortification and the amount of fortification could be critical to the cost and feasibility of a riser. At the 6,000 foot water depth in Table 6-3 for example HIPPS could be an enabling technology for a large diameter riser. A fully rated 10K riser would be problematic; 1.48 inch wall thickness is required even for a 14 inch riser. A riser relying only on a HIPPS for protection would be feasible in all sizes. A fortified riser would be very sensitive to both diameter and degree of fortification. A 14 inch fortified riser would be practical for either fortification assumption. 14 inch is probably the largest diameter that would be reasonable with the more conservative fortification requirement. Fortification would likely rule out HIPPS for a 22 inch riser.

Note that different pressure combinations, for example, a 20 K well with a HIPPS protecting a 10K pipeline and riser, would exhibit similar trends but that transition points



between controlling parameters would be different. The same would be expected for markedly different grades of pipe.

The same cases are tabulated in Table 6-4 but showing the lay tension for a flooded pipe rather than wall thickness. No buoyancy or other installation aids are assumed. Tension is estimated simply as water depth times submerged weight per foot flooded for the given pipe. The criteria used for highlighting the table are as follows. A lay tension less than 1,000 kips is generally available from a number of vessels and no special formatting is used.

For lay tensions between 1,000 and 2,000 kips a very limited number of vessels exist, only one or two of which are currently believed capable of installing an SCR in this range. These cases are shown in red text with yellow highlighting.

Above 2,000 kips the values are additionally shown in bold indicating they are not currently installable.

Table 6-4 gives a similar picture as that for the wall thicknesses. The 6 inch pipeline is again insensitive to the use of a HIPPS or the fortification of the riser at all depths. In the shallower water depths only the largest diameter risers would see any benefits from a HIPPS or be sensitive to fortification.

At 6,000 foot water depth a 22 inch riser would require a HIPPS for feasibility and would be sensitive to the degree of fortification, likewise at 8,350 foot water depth where the 14 inch riser would also become sensitive to the degree of fortification. At deeper depths the largest risers are not feasible with current installation equipment and even the 14" riser becomes increasingly dependent on HIPPS for feasibility until it too becomes uninstallable.

**Table 6-4 Effect of Fortification Requirements on Lay Tension Flooded (Kips)**

| Depth (ft) | Case | Pipeline OD | | |
|---------------|--|------------------|------------------|------------------|
| | | 6.625 (in) | 14 (in) | 22 (in) |
| 2,475 | 5K Pipeline | 39 | 176 | 436 |
| 2,475 | With HIPPS & No Riser Fortification (@ E) | 55 | 245 | 609 |
| 2,475 | With HIPPS & Point B Riser Fortification | N/A ¹ | N/A ¹ | N/A ¹ |
| 2,475 | With HIPPS & Point E Riser Fortification (@ E) | 55 | 245 | 609 |
| 2,475 | Fully rated 10K Riser | 100 | 446 | 1,104 |
| 3,750 | 5K Pipeline (@ A) | 51 | 230 | 569 |
| 3,750 | With HIPPS & No Riser Fortification (@ B) | 81 | 363 | 896 |
| 3,750 | With HIPPS & Point B Riser Fortification (@ B) | 81 | 363 | 896 |
| 3,750 | With HIPPS & Point E Riser Fortification (@ D) | 101 | 448 | 1,110 |
| 3,750 | Fully rated 10K Riser | 150 | 668 | 1,649 |
| 6,000 | 5K Pipeline (@ C) | 99 | 448 | 1,103 |
| 6,000 | With HIPPS & No Riser Fortification | 126 | 553 | 1,368 |
| 6,000 | With HIPPS & Point B Riser Fortification | 164 | 731 | 1,797 |
| 6,000 | With HIPPS & Point E Riser Fortification | 201 | 894 | 2,208 |
| 6,000 | Fully rated 10K Riser | 234 | 1,038 | 2,562 |
| 8,350 | 5K Pipeline (@ C) | 166 | 731 | 1,813 |
| 8,350 | With HIPPS & No Riser Fortification | 166 | 731 | 1,813 |
| 8,350 | With HIPPS & Point B Riser Fortification | 268 | 1,191 | 2,946 |
| 8,350 | With HIPPS & Point E Riser Fortification | N/A ² | N/A ² | N/A ² |
| 8,350 | Fully rated 10K Riser | 313 | 1,402 | 3,472 |



| Depth (ft) | Case | Pipeline OD | | |
|---------------|---|------------------|--------------------|--------------------|
| | | 6.625 (in) | 14 (in) | 22 (in) |
| 11,000 | 5K Pipeline | 260 | 1,154 | 2,847 |
| 11,000 | With HIPPS & No Riser Fortification | 260 | 1,154 | 2,847 |
| 11,000 | With HIPPS & Point B Riser Fortification (@ F) | 402 ³ | 1,790 ³ | 4,412 ³ |
| 11,000 | With HIPPS & Point E Riser Fortification | N/A ² | N/A ² | N/A ² |
| 11,000 | Fully rated 10K Riser | 402 | 1,790 | 4,412 |
| 16,000 | 5K Pipeline | 488 | 2,177 | 5,373 |
| 16,000 | With HIPPS & No Riser Fortification | 488 | 2,177 | 5,373 |
| 16,000 | With HIPPS & Point B Riser Fortification | N/A ³ | N/A ³ | N/A ³ |
| 16,000 | With HIPPS & Point E Riser Fortification | N/A ² | N/A ² | N/A ² |
| 16,000 | Fully rated 10K Riser | 545 | 2,435 | 6,021 |
| 18,000 | 5K Pipeline <u>extrapolated</u> | 604 | 2,682 | 6,624 |
| 18,000 | With HIPPS & No Riser Fortification <u>extrapolated</u> | 604 | 2,682 | 6,624 |
| 18,000 | With HIPPS & Point B Riser Fortification | N/A ³ | N/A ³ | N/A ³ |
| 18,000 | With HIPPS & Point E Riser Fortification | N/A ² | N/A ² | N/A ² |
| 18,000 | Fully rated 10K Riser <u>extrapolated</u> | 604 | 2,682 | 6,624 |

Notes:

1. The 2,475 foot water depth is too shallow for the Point B Riser Fortification Curve to apply. The 5,000 psi burst rating controls both pipeline and riser design, i.e., collapse is not yet an issue. The Point B riser fortification assumption is that the riser is fortified with respect to the pipeline in shallow water if both are designed to their respective design factors to just meet burst requirements.



2. At 7,800 foot water depth the Point E Riser Fortification Curve would require a wall thickness equal to that required to resist full wellhead shut in pressure. At greater depths it would require a wall thickness greater than that required to resist full wellhead shut in pressure and is thus not applicable.
3. At 11,000 foot water depth the Point B Riser Fortification Curve requires a wall thickness equal to that required to resist full wellhead shut in pressure. At greater depths it would require a wall thickness greater than that required to resist full wellhead shut in pressure and is thus not applicable.

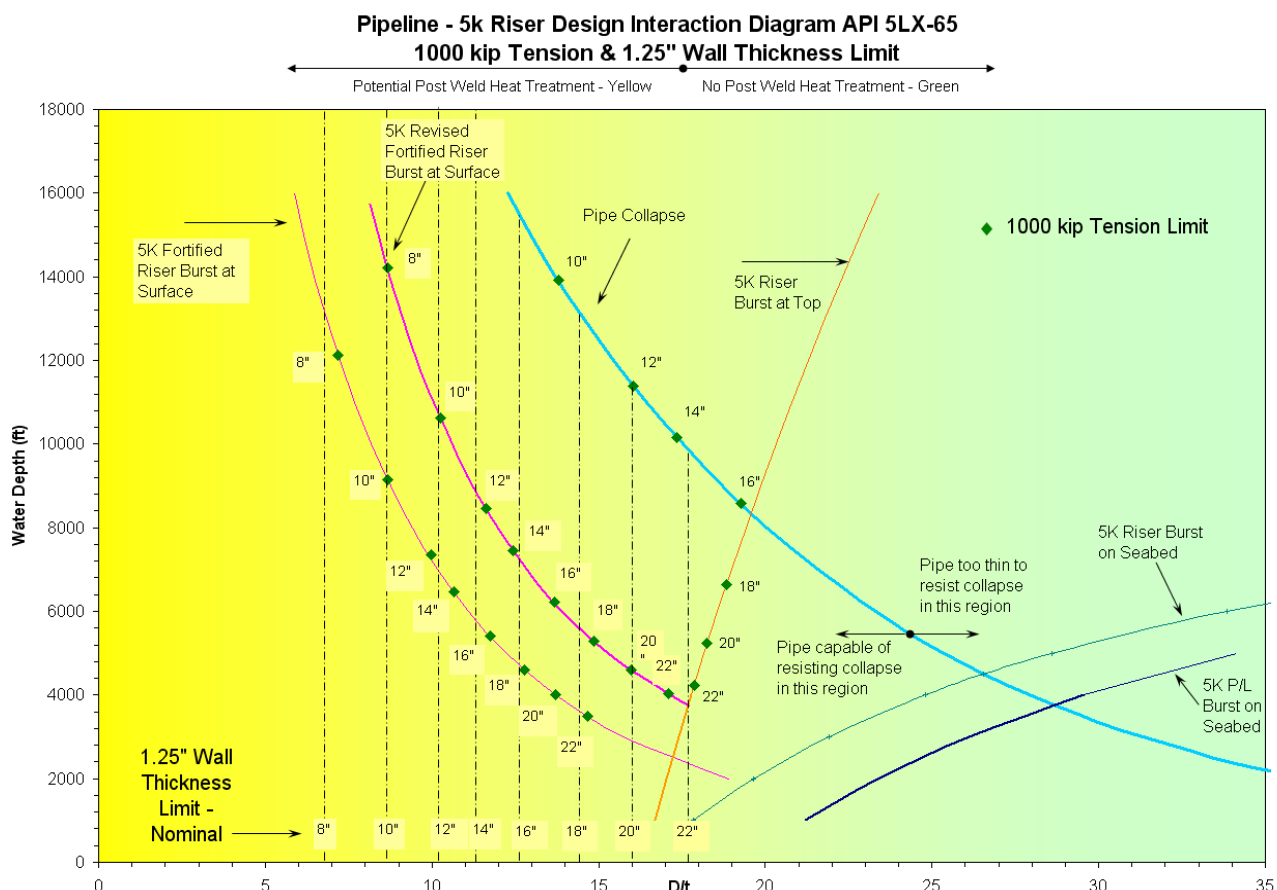
An alternative way of representing this data, for a larger number of cases but with the same assumptions as for Table 6-3 and Table 6-4, is given in Figure 6-10, a modified version of Figure 6-6.

The dashed vertical lines in the figure are the D/t values at which the pipeline wall thickness is 1.25 inch for the indicated diameter. D/t values to the left of these lines have a greater thickness for the indicated diameter and will be harder to weld.

Looking at the line for 20 inch diameter by 1.25 inch wall pipe it is apparent that a fortified riser would reach this wall thickness at a depth of between 3,000 and 4,600 feet with the fortification factors assumed for this study. If instead if no fortification is required and the HIPPS relied on to protect the riser and personnel on the facility, a depth of 11,600 feet would be possible for the same wall thickness.

The diamonds shown on the design curves and labeled with diameters show the depth and D/t at which the given diameter requires 1,000 kips of tension capability to install the pipe flooded. For example a 16 inch diameter pipe reaches the limit between 5,400 and 6,100 feet with the fortification factors assumed for this study. If instead if no fortification is required and the HIPPS relied on to protect the riser and personnel on the facility, a depth of 8,600 feet would be possible for the same tension.

It is also apparent whether the wall thickness limit or the tension limit would control a given case. For example, with a 16 inch riser, a depth limited by the 1.25 inch wall thickness would be reached for the most fortified assumption before reaching a depth controlled by the tension limit. With lesser or no fortification requirements the tension limited depth would be reached before the wall thickness limited depth.



Yet another way of illustrating the limitations, again with the same assumptions as before, is shown in the following more self explanatory illustrations.

In these figures, similar to those above, the 5K riser label applies to the envelope of diameter vs. water depth for an unfortified riser. The revised fortified 5K riser label applies to the envelope of the continuous fortification curve riser and the fortified riser label applies to the originally developed fortification curve.

Note that similar tables and graphs to those in this section could be developed for any number of other combinations of HIPPS rating, protected pipeline rating, pipe grade, fortification factor and limitation criteria. The behavior will be similar but the degree of constraint will, of course, vary.



1.25" Wall Thickness Limit, 5k Riser

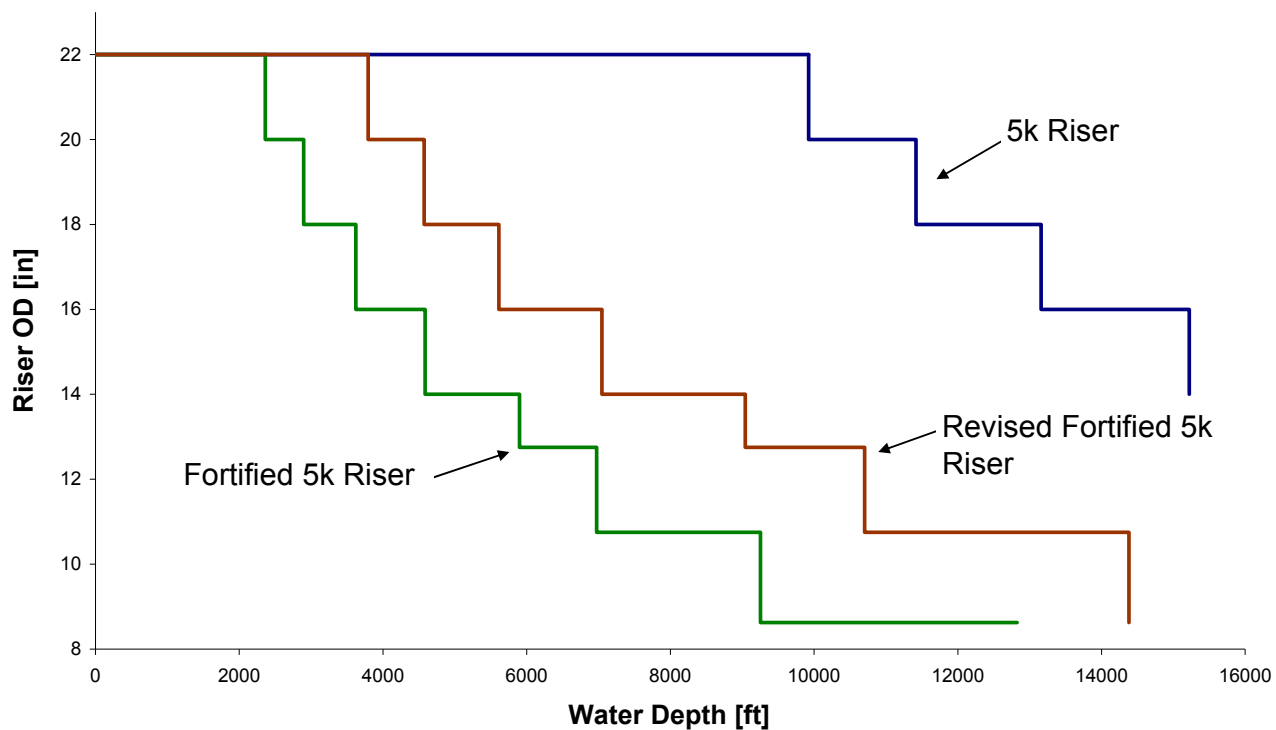


Figure 6-11 Installation Envelopes for 1.25 inch Wall Thickness



1.5" Wall Thickness Limit, 5k Riser

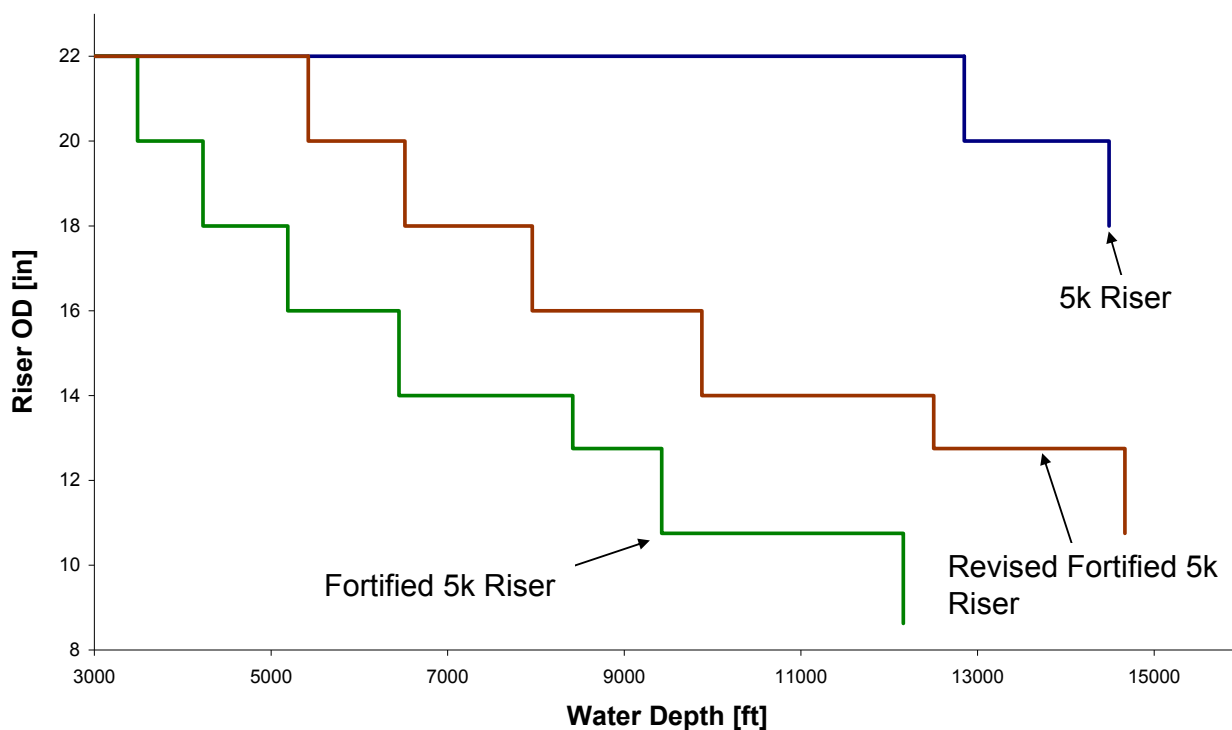


Figure 6-12 Installation Envelopes for 1.50 inch Wall Thickness



1000 kip Lay Tension Water Depth Limit, 5k Riser

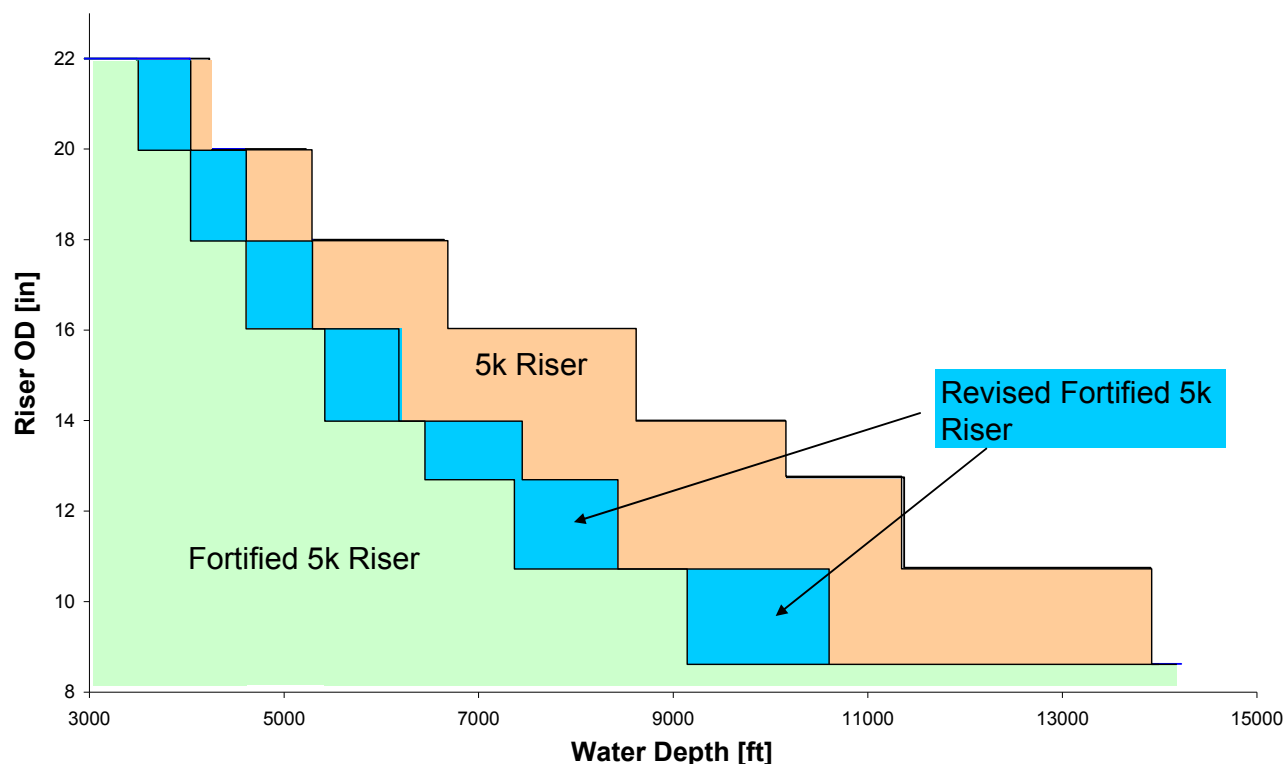


Figure 6-13 Installation Envelopes for 1,000 Kips Lay Tension Flooded

6.3.3 Methodology Check

The general approach taken to assemble the interaction diagrams was done once with ASME B31 hoop stress equations and factors and using a Murphy and Langner collapse formulation¹ to develop the concept and then using API 1111 to prepare the diagrams presented in this study.

The two methods were plotted together to serve as a check in Figure 6-14.

Good correlation was obtained. As expected the API 1111 approach (solid lines) produced slightly thinner wall thickness designs compared to the ASME B31 approach (dashed lines). This can be seen in Figure 6-14 where the API lines are parallel and just to the right of the corresponding ASME lines.

¹ Murphy, C.E. and Langner, C.G., "Ultimate Pipe Strength Under Bending, Collapse, and Fatigue." Proceedings 4th International Offshore Mechanics and Arctic Engineering Symposium, Dallas, February 1985.

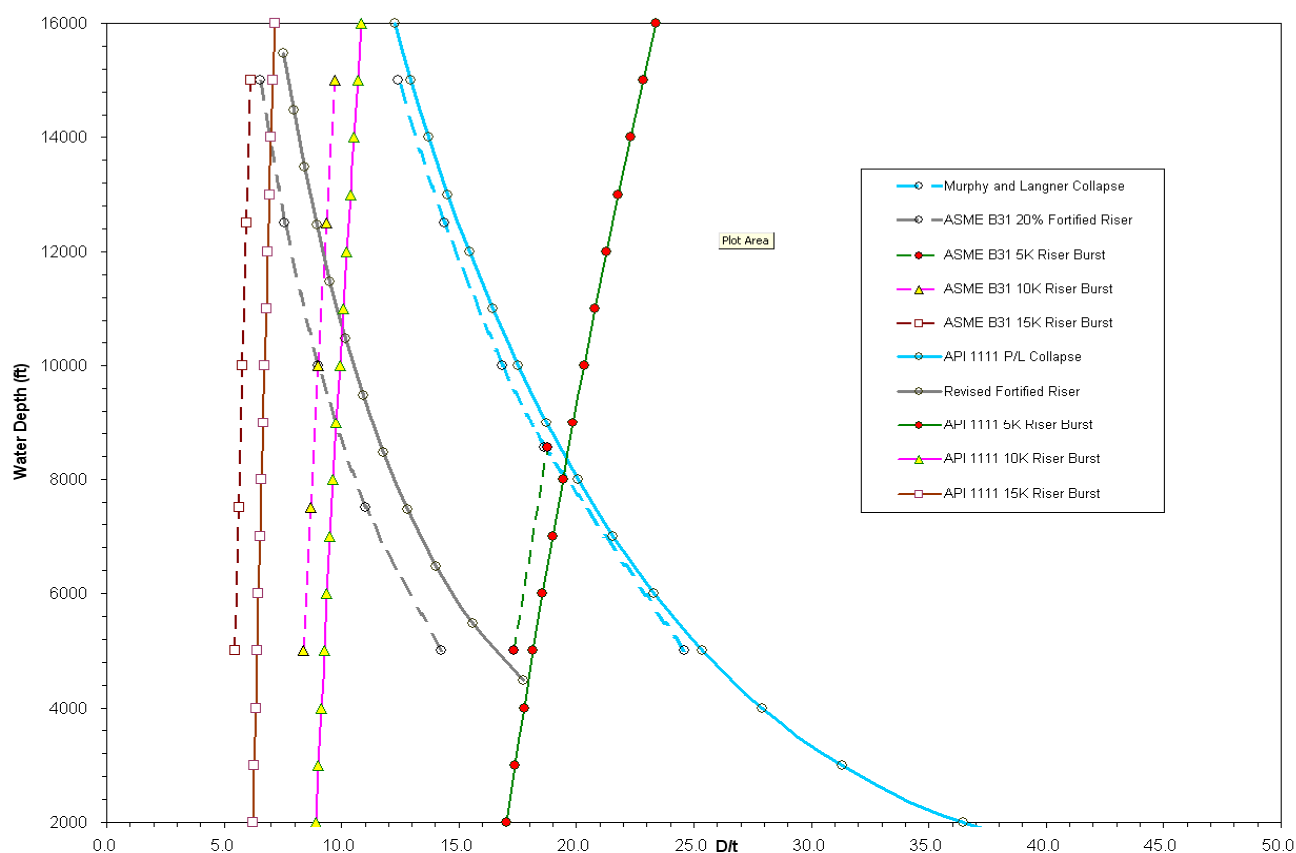


Figure 6-14 Cross Check API 1111 vs. ASME B31

6.4 Discussion of Additional Topics

6.4.1 Alternative Means of Protecting the Riser

This study has been based on the need to provide a protective segment of pipeline to ensure that a HIPPS failure does not lead to a failure in the riser but rather to a failure at some distance from the manned facility. The consequences of such a failure, remote from the facility, would not be safety related but only environmental and economic.

Alternative means to the same end are also acceptable. However, the alternative means face the same issue of external pressure. Any mechanism such as a rupture disk on the pipeline would have to overcome the differential pressure on the outside before it can relieve pressure in the line while at the same time resisting the external pressure so as not to allow water to leak into the line. The use of a Safety Integrity Level (SIL) for the HIPPS with a rating greater than 3 might be considered an alternative but such an ultra-high reliability may be hard to come by in the subsea environment.



A relief mechanism above water and upstream of the platform ESD boarding valve avoids the issue of external pressure. It would be tied into the platform relief system. Such a mechanism would protect against a slow leak, the most likely HIPPS failure mode, but might have trouble dealing with a failure of the HIPPS to close at all and the resulting full production flow. A large liquid component of the product could also be hard to deal with. In addition there is some risk introduced when any connections are placed upstream of the ESD valve.

One way of overcoming this restriction might be to put a riser on a non-manned facility or have a “pressure relief” riser. This could be as simple as an umbilical, flexible pipe or SCR up to a buoy. It would be located at some point along the pipeline but remote from the terminal riser. The relief mechanism could be either on the surface or at a depth where external pressure is negligible. Navigational restriction issues, reliability, and maintenance would need to be addressed. If the relief conduit was too small or insufficiently insulated hydrates could be a problem plugging the relief system and defeating its purpose.

Another approach might be a safety instrumented subsea relief system. If sensors detected over pressure in the HIPPS protected system they would open rather than close HIPPS type valves to relieve the pipeline pressure. A check valve capable of holding against external pressure would be required to prevent ingress of water in the event of a systems failure (a fail open system would seem to be necessary) and the system would not work if external pressure was higher than that needed to protect the riser. Any failure that allowed water into the line could cause hydrate formation.

Certain pipe-in-pipe designs might also provide some protection as discussed in Section 6.4.2 below. Akin to pipe-in-pipe would be some subsea reservoir apparatus initially at internal atmospheric pressure that would take the output of a relief valve to relieve pressure on the riser. Reservoir volume would be limited and unless the HIPPS failure was mitigated the reservoir would at some point become fully pressurized and no longer serve the relief function. If a depleted subsurface reservoir was available and could be used this would overcome the volume restrictions and provide fairly unlimited relief capacity.

All these ideas would add cost to the system potentially canceling much of the benefit of a HIPPS.

6.4.2 Pipe-in-Pipe

Another issue needs to be addressed in the case of a pipe-in-pipe flowline and riser. While, due to the absence of external pressure, the internal pipeline will fail before the riser some designs could allow the pressure to migrate along the annulus, eventually



reaching the top of the riser where the external pipeline has no pressure and would be most expected to fail.

Having a pressure tight bulkhead separating the pipeline from the pipe-in-pipe riser would be one means of addressing this problem. Another would be to install a wet insulated fuse section of pipe in the line, external pressure conditions permitting.

One advantage of a pipe-in-pipe system is that the annulus could provide a reservoir to relieve over pressure in the riser. As noted in Section 6.4.1, volume would be limited and unless the HIPPS failure was mitigated the annulus would at some point become fully pressurized and no longer serve the relief function.

6.4.3 Alternative Risers

If a riser similar to those addressed in this study is not feasible an alternative type of riser may be required. An increase in material strength say due to the use of high strength steel or titanium would be one way of reducing riser weight but these might also increase the difficulty of welding.

A free standing riser might be a way to remove the riser from proximity to the facility and introduce the required safety without fortification.

6.5 Conclusions

Riser fortification will, under certain conditions, constrain the riser to be stronger than if the HIPPS is considered adequate to protect the riser and facilities.

This may cause the riser wall thickness to increase to the point where pipe procurement, welding, and/or installation are difficult or impossible to accomplish.

Graphical methods and tools presented in this section can be used to determine where these constraints will occur.

6.5.1 Typical Case Summary

This study addresses a typical case of a gas well with a 10K shut in wellhead pressure flowing through a 10K HIPPS into a 5K MAOP pipeline and riser for a range of depths and pipe diameters. Assuming a 65 ksi pipe material grade, the maximum fortification factor recommended in Section 6.2.2, and a uniform riser wall thickness from top to bottom, the constraints are as follows:

Riser design at the shallower depths is governed by burst. However, starting at 3,750 foot water depth and running up to 11,000 foot depth, riser fortification governs. At depths greater than 11,000 feet the riser is fully rated to resist the 10K wellhead shut in pressure



and needs no HIPPS or fortification. Note that extrapolating shows that around 18,000 foot depth pipe collapse would be expected to govern the riser design.

If the system is designed with a 5K non-fortified riser, the internal riser pressure at the top would control the design at depths less than about 8,350 feet. At depths greater than this, the bottom of the riser will collapse unless the riser wall thickness is increased, so the riser design follows the pipeline collapse line. Note that at 10,000 foot water depth the flowline would no longer require a HIPPS for protection but be fully rated. A HIPPS could still protect the riser to a depth of 11,000 feet at which point the riser also becomes fully rated. At this point the fortification requirement would no longer affect the required wall thickness and no benefit would accrue from using a HIPPS and a non-fortified riser.

Table 6-5 summarizes the limitations imposed for the typical case described above vs. pipe diameter. The less conservative fortification factor used in the study is illustrated.

Table 6-5 Maximum Depth vs. Constraints for Fortified & Unfortified Risers

| Pipe Diameter (inch) | Maximum Water Depth at Limiting Constraint (ft) | | | | | |
|-------------------------|---|---------------------|-------------------|--------------------|-------------------|-------------------|
| | Fortified Riser Revised Curve | | | Un-Fortified Riser | | |
| | Lay Tension | Wall Thickness | | Lay Tension | Wall Thickness | |
| | 1000 Kips Maximum | 1.25 inch Maximum | 1.50 inch Maximum | 1000 Kips Maximum | 1.25 inch Maximum | 1.50 inch Maximum |
| 6.625 | N/A ¹ | N/A ¹ | N/A ¹ | N/A ¹ | N/A ¹ | N/A ¹ |
| 8.625 | N/A ¹ | N/A ¹ | N/A ¹ | N/A ¹ | N/A ¹ | N/A ¹ |
| 10.75 | 10,600 ² | N/A ³ | N/A ³ | 13,900 | N/A ³ | N/A ³ |
| 12.75 | 8,400 | 10,600 ⁴ | N/A ⁵ | 11,400 | N/A ⁵ | N/A ⁵ |
| 14.00 | 7,400 | 9,000 | N/A ⁵ | 10,100 | N/A ⁵ | N/A ⁵ |
| 16.00 | 6,200 | 7,200 | 9,800 | 8,600 | 15,400 | N/A ⁵ |
| 18.00 | 5,300 | 5,600 | 8,000 | 6,700 | 13,200 | 16,400 |
| 20.00 | 4,600 | 4,600 | 6,700 | 5,200 | 11,600 | 14,600 |
| 22.00 | 4,000 | 3,750 | 5,400 | 4,200 | 9,900 | 12,800 |



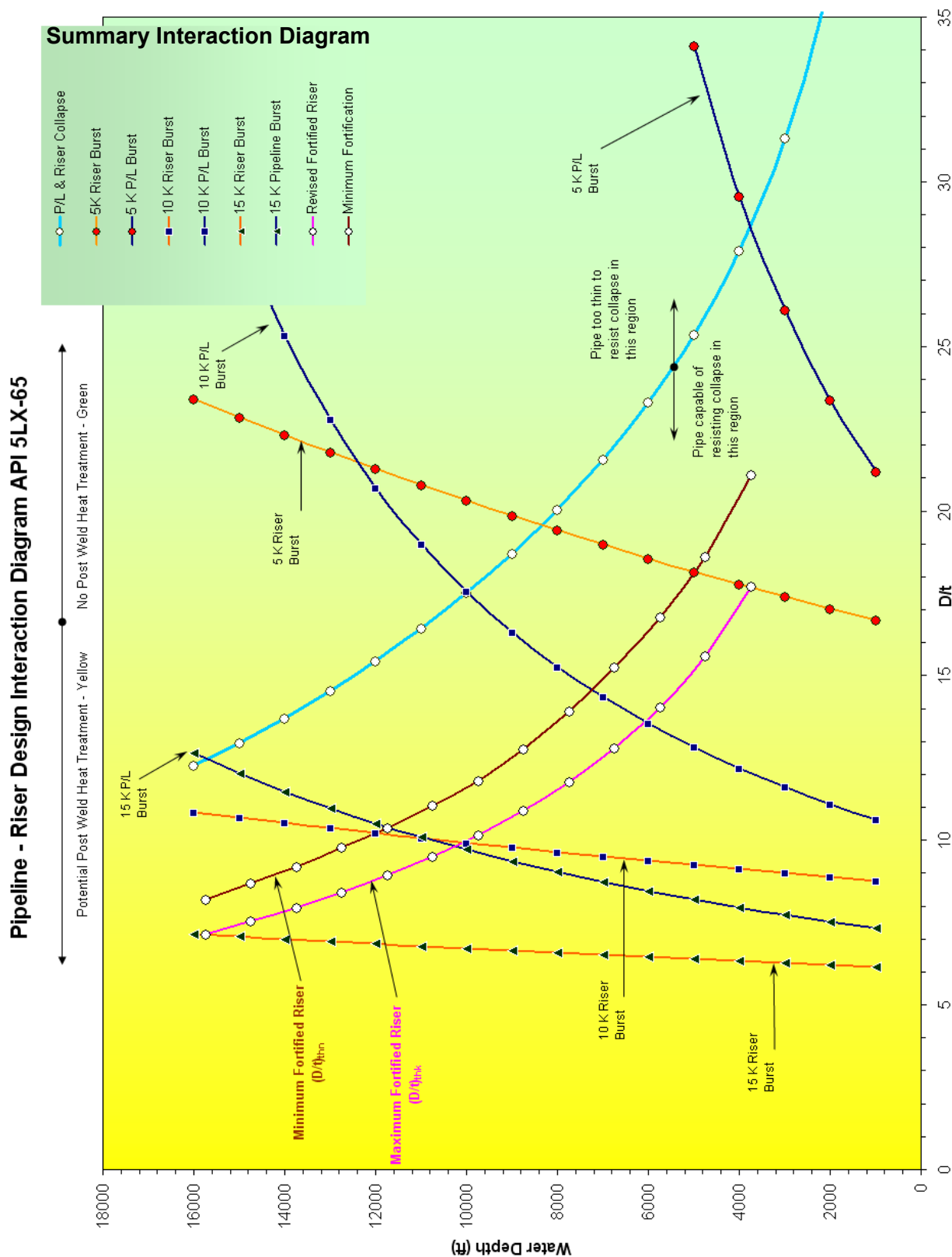
Notes:

1. Fully rated risers at 11,000 foot water depth do not exceed the wall thickness and tension constraints.
2. 10.75 inch fortified or fully rated riser exceeds 1000 kip tension limit from approximately 10,600 foot water depth to 12,400 foot water depth. At greater depths a fully rated riser can be laid because internal gas head in the riser reduces the internal pressure at the top of the riser sufficiently that wall thickness reduces to the point the weight falls back within the feasible level.
3. Fully rated risers do not exceed the wall thickness constraints.
4. 12.75 inch diameter riser with 1.25 inch wall thickness is inadequate for fortification or full rating from approximately 10,600 foot water depth to 12,400 foot water depth. At greater depths a fully rated riser has a thinner wall because internal gas head in the riser reduces the internal pressure at the top of the riser sufficiently. At lesser depths 1.25 inch wall provides adequate fortification.
5. Wall thickness limit not reached at any depths examined in the study.



6.5.2

Summary Interaction Diagram





6.5.3 Recommendations for Application of this Study

This investigation illustrates the sensitivity of HIPPS protected flowline riser designs to a riser fortification factor intended to provide an extra margin of safety above that given by the HIPPS.

The study illustrates where limits are reached and shows that both the degree of fortification and the values of the limiting factors matter when examining whether a given application would be rendered infeasible due to the fortification requirement.

The study also illustrates that the degree of fortification should be concomitant to the risk level in the event of a HIPPS failure and proposes a range of fortification factors based on risk level.



7. TASK 700 – CODE REVIEW AND RECOMMENDATIONS ON REGULATION

7.1 Introduction

This report provides a brief summary of API RP 17O and discusses how the normative references within apply to different parts of the HIPPS. The codes related to design of the safety instrumented system (SIS), IEC 61508 and IEC 61511 are explored in more depth with guidance on their applicability to a subsea HIPPS. The report concludes with a discussion of pipeline codes and their relation to HIPPS.

7.1.1 Scope

This study is limited to reviewing API RP 17O and discussing the code/standard references within, to exploring the IEC 61508 and IEC 61511 codes and their relation to a subsea HIPPS, and providing some discussion on pipeline codes as they relate to HIPPS.

7.1.2 Problem Statement

HIPPS will be subject to the typical API and ISO code requirements applying to subsea equipment.

The codes with specific relevance to HIPPS are IEC 61508, IEC 61511 and API RP 17O.

IEC 61508 sets out the parameters for determining, implementing and certifying the Safety Integrity Level (SIL) of a safety system. Under the IEC code, the system operator reviews and establishes the necessary SIL on a scale of 0 to 4 (the MMS has indicated that a HIPPS for the Gulf of Mexico should have a mandated minimum SIL of 3). IEC 61511 helps determine how to configure a system with the acceptable fault tolerance capabilities to match the SIL. Establishing the actual achieved SIL includes assessment of component reliability. The limited use worldwide of HIPPS in subsea environments may undermine the statistical basis of these component reliability assessments.

The study would review the codes and their applicability for the specific conditions of HIPPS in the GoM and make recommendations concerning the interpretation of the IEC codes.

7.2 HIPPS Code Review

API RP 17O, Recommended Practice for Subsea High Integrity Pressure Protection Systems (HIPPS), was released as a first edition in October 2009 for use by industry. Although this document is only a recommended practice, it is likely that it will be a de facto controlling specification for HIPPS in the Gulf of Mexico.



API RP 17O makes reference to several well-established recommended practices and specifications. Table 7-1 lists these normative references. The subsections below will summarize how API RP 17O uses the normative references.

Table 7-1 API RP 17O Normative References

| Ref. | Code/Standard | Title |
|------|--|--|
| [1] | API Specification 6A/ISO 10423 | Specification for Wellhead and Christmas Tree Equipment |
| [2] | API Recommended Practice 6HT | Heat Treatment and Testing of Large Cross Section and Critical Section Components |
| [3] | API Recommended Practice 17A/ISO 13628-1 | Design and Operation of Subsea Production Systems—General Requirements and Recommendations |
| [4] | API Recommended Practice 17C/ISO 13628-3 | Recommended Practice on TFL (Through Flowline) Systems |
| [5] | API Specification 17D/ISO 13628-4 | Subsea Wellhead and Christmas Tree Equipment |
| [6] | API Specification 17F/ISO 13628-6 | Specification for Subsea Production Control Systems |
| [7] | API Recommended Practice 17H/ISO 13628-8 | Recommended Practice for Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems |
| [8] | ANSI/ASME B31.3 | Process Piping |
| [9] | ANSI/ASME B31.8 | Gas Transmission and Distribution Piping Systems |
| [10] | AWS D1.1 | Structural Welding Code—Steel |
| [11] | IEC 61508, Parts 1 to 4 | Functional safety of electrical/electronic/programmable electronic safety-related systems |
| [12] | IEC 61511, Part 1 | Functional safety—Safety instrumented systems for the process industry sector |
| [13] | ANSI/SAE J343 | Test and Test Procedures for SAE 100R Series Hydraulic Hose and Hose Assemblies |



| Ref. | Code/Standard | Title |
|------|---------------|---|
| [14] | ANSI/SAE J517 | Hydraulic Hose |
| [15] | SAE AS 4059 | Aerospace Fluid Power—Cleanliness Classification for Hydraulic Fluids |

7.2.1 API Specification 6A/ISO 10423

API RP 17O requires that HIPPS valves be rated for standard or sandy service, as determined by API 6A/ISO 10423.

Material properties shall comply with API 6A/ISO 10423. Temperature and material classes are to be specified as defined in API 6A/ISO 10423 and API 17D/ISO 13628-4.

Welding on pressure-containing and pressure-controlling equipment shall comply with API 6A/ISO 10423 PSL 3. Structural welds are required to conform to API 6A/ISO 10423 or another documented welding code such as AWS D1.1. Corrosion resistant overlays shall comply with API 6A/ISO 10423. 'Critical' welds shall meet API 6A/ISO 10423 PSL 3 quality control and testing requirements.

HIPPS valves that comply with API 6A/ISO 10423 shall be drift tested with an API 6A/ISO 10423 drift mandrel, if required.

API 6A/ISO 10423 should be referenced for marking locations of API RP 17O monogrammed equipment.

API 6A/ISO 10423 Annex F is referenced for performance validation of HIPPS final elements.

7.2.2 API Recommended Practice 6HT

For pressure-containing forged material, forging practices, heat treatment, and test coupon requirements are to be in accordance with API 6HT. API RP 17O makes the additional requirement that the test coupon must accompany the qualified forged material through all thermal processing.

7.2.3 API Recommended Practice 17A/ISO 13628-1

Color selection and marking of HIPPS equipment are to be per API RP 17A/ISO 13628-1.



7.2.4 API Recommended Practice 17C/ISO 13628-3

API RP 17C/ISO 13628-3 is referenced for the design of transitions where the HIPPS isolation valves have a bore which differs from the pipe bore. This RP is also specified for drift testing of runs that require passage of TFL tooling.

7.2.5 API Specification 17D/ISO 13628-4

API 17D/ISO 13628-4 is the main specification used for design of the HIPPS final elements and some aspects of the controls equipment (materials, for instance). API 17D/ISO 13628-4 is pervasive throughout API RP 17O with regards to HIPPS valve design and specification. Some references to API 17D/ISO 13628-4 include:

- Temperature ratings;
- Actuator design requirements;
- Material class specification;
- External pressure design;
- Transportation and installation;
- Product specification levels (PSL);
- Corrosion issues;
- Valve design;
- Factory acceptance testing (FAT);
- Closure bolting;
- Coatings;
- Pressure testing;
- Lifting device design;
- Marking requirements; and
- Validation testing.

7.2.6 API Specification 17F/ISO 13628-6

API 17F/ISO 13628-6 is specified for design of the HIPPS electrical power system.



Hydraulic control elements are required to be specified in regards to working, design, and test pressures per API 17F/ISO 13628-6.

Subsea control communications protocol is required to conform to applicable industry standards as defined in API 17F/ISO 13628-6.

API 17F/ISO 13628-6 is specified along with IEC 61508 and IEC 61511 for hardware and software requirements of the HSCM.

Selection of sensors should include reference to API 17F/ISO 13628-6 and IEC 61508.

HIPPS umbilical jumpers (flying leads) are required to be designed per API 17F/ISO 13628-6.

API 17F/ISO 13628-6 is referenced for materials specification requirements for the HIPPS control system.

Quality control of HIPPS final element-mounted devices is governed by API 17F/ISO 13628-6, in addition to API 17D/ISO 13628-4 and IEC 61511.

API 17F/ISO 13628-6 is allowed as an alternative to API RP 17O requirements for hyperbaric and temperature testing of DCVs.

7.2.7 API Recommended Practice 17H/ISO 13628-8

ROV intervention points and their respective functions are required to conform to API RP 17H/ISO 13628-8.

7.2.8 ANSI/ASME B31.3

ANSI/ASME B31.3 is specified as an option to ANSI/ASME B31.8 as a primary reference for design of piping and pressure-related components and for design of piping structural support elements. Elsewhere in API RP 17O, it is required that allowable stresses in piping and tubing be in conformance with ANSI/ASME B31.3, so it appears that ANSI/ASME B31.8 may not be as generally acceptable for design of piping, as is implied previously. ANSI/ASME B31.3 is also referenced with regards to cold bending of tubing.

See further discussion related to subsea use of B31 codes in Section 7.4.

7.2.9 ANSI/ASME B31.8

ANSI/ASME B31.8 is specified as an option to ANSI/ASME B31.3 as a primary reference for design of piping and pressure-related components and for design of piping structural support elements.



7.2.10 AWS D1.1

AWS D1.1 is suggested as one alternative for API 6A/ISO 10423 welding requirements for non-pressure containing structural codes. AWS D1.1 is not mandated, but is suggested as an option to meet the requirement that structural welds be performed to a documented structural welding code.

AWS D1.1 is specified for quality control and testing of 'non-critical' structural welds. See section 7.2.1 for discussion of 'critical' welds.

7.2.11 IEC 61508, Parts 1 to 4

See Section 7.3.

7.2.12 IEC 61511, Part 1

See Section 7.3.

7.2.13 ANSI/SAE J343

API RP 17O requires that hose assemblies (ref. Section 7.2.14) be validated per ANSI/SAE J343.

7.2.14 ANSI/SAE J517

API RP 17O requires that hose assembly design be performed per ANSI/SAE J317.

7.2.15 SAE AS 4059

SAE AS 4059 is referenced for the portions of API RP 17O that address the need for hydraulic fluid cleanliness. After assembly of the HIPPS, it is required to flush all tubing and hydraulic equipment to an SAE AS 4059 cleanliness level agreed between the manufacturer and the purchaser. Also, SAE AS 4059 cleanliness levels are specified for control fluid cleanliness for DCV validation tests.

7.3 Guidance on IEC Requirements

7.3.1 Introduction

Safety Instrumented Systems (SIS) of which subsea HIPPS is a subset have been used for many years within the process sector. The original approach for the requirements of Codes and Standards was prescriptive in application for the offshore sector stating specifics in terms of the equipment to be used for a particular process application. In more recent times, the increased complexity of new applications and of new equipment has made the prescriptive approach less than completely adequate. This is more the case



where programmable equipment with complex failure modes is used for safety applications. Some years ago the international community recognized the need for new standards and the International Electrotechnical Commission (IEC) developed a new generic standard IEC 61508 and adopted a risk-based approach.

IEC 61508 (Functional Safety of Electrical / Electronic / Programmable Electronic Safety related Systems) was originally published in several parts between 1998 and 2000. Since publication of IEC 61508, the process sector has had significant experience in the application of the risk based approach. However, before IEC 61508 was published a need was recognized for a process sector standard to aid application of the generic standard IEC 61508. The result was IEC 61511 (Safety Instrumented Systems for the Process Industry sector) which comprising of three parts was originally published in 2003.

The risk based approach more tailors equipment to the needs of the application and has significant safety and economic benefits. This approach does however, demand more management, competency, planning, and technical judgment during all stages of realization, from the initial hazard and risk assessment through to operation, maintenance and modification as would be applicable to a subsea HIPPS.

7.3.2 IEC Standards

7.3.2.1 IEC 61508 and IEC 61511

The IEC have developed a generic standard for achieving functional safety by the use of safety related control or production systems based on Electrical / Electronic / Programmable Electronic (E/E/PE) technologies. Functional safety is defined as that part of the overall safety which depends on the correct functioning of a process or equipment such as a SIS to perform the actions necessary to achieve or maintain tolerable risk.

The standard applies to a wide range of industries. For example, safety instrumented systems involved with lifting equipment, emergency stopping systems on machinery or railway signaling systems etc, thus IEC 61508 has evolved as and recognized as good practice in various sectors and thus is also requisite to the planning, design and development of subsea HIPPS.

IEC 61508 is published in several parts inclusive of the following:

IEC 61508 (Functional Safety of Electrical / Electronic / Programmable Electronic Safety related Systems)

Part 1: General requirements



Part 2: Requirements for Electrical / Electronic / Programmable Electronic safety related systems

Part 3: Software requirements

Part 4: Definitions and abbreviations

Part 5: Examples of methods for the determination of safety integrity levels

Part 6: Guidelines on the application of IEC 61508-2 and IEC 61508-3

Part 7: Overview of techniques and measures

7.3.2.2 IEC 61511 Process Sector Standard

A number of sector or subsystem standards based on IEC 61508 have been developed or are under development. These include sector standards for the nuclear power plants, process sector, machinery sector and power drive systems. The process sector standard IEC 61511 applies to a range of industries including oil and gas production, oil refining, chemicals, pulp and paper, non nuclear power generation etc. IEC 61511 incorporates experience from national and industry standards e.g. IEC 61511 incorporates the pragmatic approach to SIS used in ANSI/ISA 84.01 and is key to the requirements of subsea HIPPS.

IEC 61511 is published in three parts inclusive of the following:

IEC 61511 (Safety Instrumented Systems for the Process Industry Sector)

Part 1: Framework, definitions, system, hardware and software

Part 2: Guidelines on the application of IEC 61511-1

Part 3: Guidelines for the determination of the required safety integrity levels

7.3.3 Relationship between IEC 61508 and IEC 61511

The relationship between IEC 61508 and IEC 61511 in the process industries as follows:

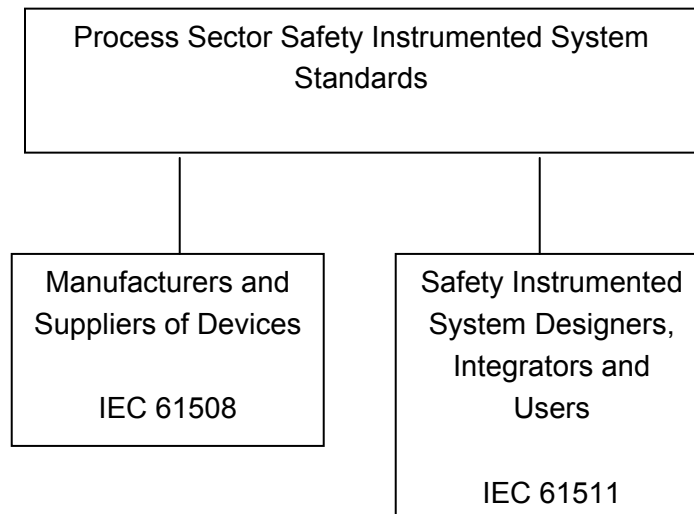


Figure 7-1 Relationship between IEC 61508 and IEC 61511

From this it will be seen that end users of SIS (for example the Operators) are primarily concerned with IEC 61511 in the specification of requirements and also in SIS operations and maintenance. The equipment and system suppliers are governed primarily by IEC 61508.

7.3.4 IEC Standards Key Requirements

This section reviews the key requirements of the two IEC Standards. It is also noted here that IEC 61511 will have the primary focus from the end user in the process sector where responsibility for operations and maintenance of subsea HIPPS will be of more consequence. The review focuses on the specification of the required performance and the required architecture to meet that performance. The IEC standards also place requirements on installation and commissioning, operation and maintenance, modification and decommissioning.

The two IEC standards are complex and the user requires an in depth knowledge and knowledge of both. This section will introduce some of the key requirements.

7.3.4.1 Safety Lifecycle

IEC 61508 uses the “safety lifecycle” as a framework to structure the activities relating to the specification, design, integration, operation, maintenance and eventual decommissioning of an SIS. The safety lifecycle approach should ensure that all activities relating to functional safety are managed in a planned and methodical way, with each phase having defined inputs and outputs. This includes verification at the conclusion of



each phase to confirm the required outputs have indeed been produced as planned. The various phases of the safety lifecycle are illustrated in Figure 7-2 below.



Figure 7-2 Phase of Safety Lifecycle

7.3.4.2 Identification of Hazards and Safety Functions

A systematic identification of all hazards should be undertaken. The process should consider the event sequences leading to the hazard. The initial risk (probability of occurrence and potential consequences) associated with each hazard should be determined. If practical, hazards should be eliminated by inherent design. The initial risk should be compared to the tolerable risk. IEC 61508 does not specify the tolerable level of risk as this varies with country, industry sector, organization etc. Therefore the user must determine the tolerable risk associated with each hazard. The required level of risk reduction for each hazard is then given by:

$$\text{Risk reduction required} = \text{Initial risk} / \text{Tolerable risk}$$



Where hazards cannot be eliminated it is a fundamental requirement of IEC 61508 that for each hazard a precise safety function is defined. The safety function specified as:

- The hazard event which is required to be terminated;
- The action to be taken to terminate the hazard;
- The time taken to terminate the hazard;
- The required level of risk reduction; and
- The mode of operation.

The mode of operation of a SIS is either specified as low demand or high demand / continuous. Low demand is defined as a demand rate of the SIS of less frequent than once a year. Hence subsea HIPPS will tend to fall into low demand mode.

7.3.4.3 Allocation of Safety Requirements and Safety Integrity Level

The next stage is to allocate how each required safety function will be achieved. One safety function may be allocated to one or more layers of protection. A SIS constitutes one possible layer of protection. Other technologies could also be used e.g. mechanical pressure relief devices.

Where a SIS is proposed the required level of risk reduction of the safety function must be translated into a safety integrity level (SIL) and / or probability of failure demand (PFD). IEC 61508 and IEC 61511 specify four levels of safety for a safety function, with SIL 1 being the lowest and performance SIL 4 being the highest. Use of SIL rating higher than SIL 4 is not permitted by the IEC standards. The target average of probability of failure on demand for each SIL is given in Table 7-2. The table is for the low demand of operation which is more likely to be appropriate to subsea HIPPS. The table also includes the Target Risk Reduction associated with each SIL. This TRR is not given in IEC 61508 but is included in IEC 61511.

**Table 7-2 Safety Integrity Levels (Low Demand Mode)**

| SIL | Target Average Probability of Failure on Demand (PFD) | Target Risk Reduction |
|-----|---|------------------------------|
| 1 | $\geq 10^{-2}$ to $< 10^{-1}$ | > 10 to ≤ 100 |
| 2 | $\geq 10^{-3}$ to $< 10^{-2}$ | > 100 to $\leq 1,000$ |
| 3 | $\geq 10^{-4}$ to $< 10^{-3}$ | $> 1,000$ to $\leq 10,000$ |
| 4 | $\geq 10^{-5}$ to $< 10^{-4}$ | $> 10,000$ to $\leq 100,000$ |

SILs and PFDs can be determined using qualitative, quantitative or semi quantitative methods. In some applications it may be appropriate to use more than one method. For example at a preliminary stage quantitative method may be used and as the project progresses a more detailed quantified approach may be more appropriate. A qualitative method, such as the well known risk graph will give a required SIL rating whereas a quantitative will give a target PFD. Qualitative methods can often lead to a higher SIL requirement. IEC 61508 Part 5 and IEC 61511 Part 3 give examples of SIL determination methods.

7.3.4.4 Safety Requirements Specification

The safety requirements specification for a SIS combines the safety function with the safety integrity level. An example of the safety requirement specification of a subsea HIPPS could be:

On detection of an increase in pressure to 5000 psi, the downstream facilities will be isolated from the upstream pressure source within 60 seconds. The function shall be carried out with a Safety Integrity Level of 2 and PFD shall be lower than $1.6E-3$. The mode of operation is low demand.

7.3.4.5 Design of the SIS

The design of the system architecture should be such that it ensures that the likelihood of failure to function due to either random hardware faults or systematic faults is reduced to a level consistent with the required SIL.

Random faults are defined as those faults which can occur at a random time which arise from a variety of degradation mechanisms in the hardware.



Systematic faults are those faults which will always result in a failure when a particulate combination of circumstances arises. Systematic faults are generally associated with errors in human activities such as developing a specification and software development.

Traditionally safer systems adopt architectural redundancy to achieve a low PFD of the system to function, whereas a risk based approach uses reliability measures. IEC 61508 and IEC 61511 use a combination of reliability with some redundancy to achieve the required PFD and the following must be considered:

- Hardware fault tolerance;
- Quantified failure probability, e.g.: probability of failure on demand; and
- Avoidance and / or control of system faults.

This process leads to the design of the SIS architecture, selections of subsystem components and specification of operational testing frequency.

7.3.4.6 Fault Tolerance

SIS of higher SIL rating generally requires some measure of fault tolerance. Fault tolerance is the number of dangerous faults that a sub system can tolerate and retain the capability to respond to a demand on the safety function. A sensor subsystem which relies on a single pressure transducer as input has a fault tolerance of zero. If the number of sensors is increased to two and utilizes 1oo2 voting then the fault tolerance is 1. A sensor sub system with 2oo3 voting also achieves a fault tolerance of 1. A fault tolerance of 2 could either be achieved by 2oo4 or dual 2oo3 voting.

The specification of minimum required hardware fault tolerance is presented differently in IEC 61508 and IEC 61511. For sensors final elements and non-PE logic solvers IEC 61511 requires fault tolerances of 1 and 2 for SIL 1 and SIL 2 respectively. However, IEC 61511 indicated that the indicated minimum level of fault tolerance may be reduced by 1 provided that the devices meet a number of additional requirements.

7.3.4.7 Qualified Failure Probability

The total probability of failure of each SIS due to random hardware failures must be less than the specified target given the safety requirements specification. The target can either be a numeric range associated with a given SIL or a specified PFD to meet a required risk reduction.



The PFD of a SIS is the summation of the PFDs for each sub system. For example the PFD of a subsea HIPPS system comprising of sensor (SSS), logic (LSS) and valve (VSS) sub-systems is:

$$PFD_{SIS} = PFD_{SSS} + PFD_{LSS} + PFD_{VSS}$$

The probability of failure of a sub system is dependent on:

- Component failure rates;
- Proof testing interval;
- Diagnostic testing;
- Redundancy (fault tolerance); and
- Common cause.

Failure rates for components can be derived from supplier failure data or industry data bases such as OREDA. Great care must be taken to ensure that the data is dependable. For example suppliers frequently do not receive all returns of failures from operators; the intended environment for the components may differ from that for which the failure data is applicable; and so on.

The failure probability of a system increases with time. At the point of proof testing the failure probably reduces to zero and so on. The average (AVE) failure probability is then:

$$PFD_{AVE} = 0.5 * \lambda_d * T_1$$

Where: λ_d = component failure rate to the dangerous failure modes

T_1 = proof test interval

However, if the proof tests are not comprehensive the failure probability will not reduce completely to at the point of testing and the average failure probability will correspondingly increase. The implication is that comprehensive testing must be performed during operations. Testing requirements for subsea HIPPS will be reviewed further subsequently in the next section.

Diagnostics are tests performed automatically to detect faults in the SIS that may result in unsafe or dangerous failures.

Redundancy is often used to reduce the probability of failure of a sub system due to random hardware faults. For example the PFD for 1oo2 architecture is:



$$PFD_{AVE} = (\lambda_d * T_1)^2 / 3$$

However systems incorporating redundancy are usually prone to some element of common cause failure. For example two identical sensors will suffer the same design error or two pressure transducers could both freeze up if a hydrate forms in the sensor tapping. In this case a common cause factor β is introduced and the PFD becomes:

$$PFD_{AVE} = [(1-\beta)*\lambda_d*T_1]^2 / 3 + 0.5*\beta*\lambda_d*T_1$$

β typically ranges from 1 - 20% depending on the level of diversity and a range of other factors. In high reliability redundant systems the common cause element tends to dominate the PFD value.

Reliability modeling methods are given in IEC 61508-6 and include:

- Simulation;
- Cause consequence analysis;
- Fault-tree analysis;
- Markov models; and
- Reliability block models.

7.3.4.8 Avoidance and Control of Systematic Faults

Systematic faults are often introduced from errors during specification and design phases, but can also arise from errors during integration, operation and maintenance. The faults can be present in both hardware and software. The likelihood of systematic faults cannot be easily estimated and therefore no analysis can be undertaken to determine a failure rate for a given design. IEC 61508 recommends a series of measures and techniques for the various phases of hardware and software development. The requirements increase with the required SIL.

7.3.4.9 Subsea HIPPS Issues

HIPPS should be considered to be an integral component within a layered overpressure protection system including wellhead shutdown and platform shutdown systems. This should lead to an integrated pipeline and facilities over-pressure protection philosophy. Careful consideration should be given to the likely scenarios leading to a high pressure hazard which would require a HIPPS closure. The hazards may include, topsides process upset, spurious closure of process and pipeline isolation valves, emergency shutdowns including high pressure from the wells, injection overpressure, hydrate blockages within



the lines. Realistic probabilities should be defined to each occurrence. Overestimation of hazards and probabilities of occurrence will lead to over specification of the HIPPS.

From analysis of the risks arising from the hazards, the required safety (SIL) will then be determined. The use of subsea HIPPS creates a number of complex issues which would need to be worked and resolved as early as possible in the project schedule that also include the following:

To date most subsea HIPPS have been located within gathering manifolds. However, there may be advantages if individual HIPPS are located adjacent to or some level of integration with tree equipment.

HIPPS and downstream design pressures: The downstream operating pressure must first be determined based on flowing conditions. The HIPPS trip pressure should be set such that spurious trips are avoided. The downstream design pressure should then be set at some level above the HIPPS trip pressure while avoiding over design. The level of the downstream design pressure relative to the HIPPS trip pressure will vary for different system designs, but will be higher than the trip pressure since the HIPPS does not act instantaneously. Hence the pressure immediately downstream of the HIPPS after HIPPS closure will be higher than the HIPPS trip pressure. As part of this process the output may include data relating to the requirements of fortified zones.

Operational testing requirements: A HIPPS must include operational testing facilities that allow frequent testing whilst minimizing disruption to production.

Bypass facilities: A HIPPS must include bypass facilities to allow upstream pressure to be relieved following testing or an overpressure incident. This allows the HIPPS valves to reopen prior to production restart. It is recommended that the bypass system be considered when calculating a HIPPS SIL classification in regards to *pressure integrity* after HIPPS activation. The significant components of the bypass system in regards to SIL rating are likely the bypass valves connecting the flowline upstream and downstream of the HIPPS valves. Failure of the bypass valves after HIPPS activation would allow mass transfer from upstream of the HIPPS to the downstream portion, potentially exceeding the pressure rating of the unfortified flowline. The consequences of bypass valve failures would be no different from failure of the primary HIPPS valves. A primary function of the bypass valves is to equalize pressure across the HIPPS valves prior to resetting the HIPPS by opening the HIPPS valves. However, depending on the operator philosophy, resetting the HIPPS system may not be considered a safety-critical operation. The primary function of the HIPPS is to prevent a downstream flowline from being overpressured by an upstream pressure source. Equalizing pressure and resetting a HIPPS that has performed this function is important for commercial reasons, but not



necessarily for safety-related reasons. Thus *function* of the bypass system may not be considered as part of the HIPPS SIL rating. However, it would be up to the operator to prove to the MMS that function of the bypass valves is not relevant to a SIL rating before excluding it from consideration. However, just to reiterate, the pressure integrity of the HIPPS valves should be included in the SIL rating calculations for the system.

Production availability: System development should seek to minimize any detrimental effect on production availability arising from the incorporation of HIPPS e.g.: reduction of spurious trips, improved reliability, optimized testing regime, design for deepwater intervention, retrieval / maintenance, sparing philosophy.

Project proposals should enable a full understanding of the issues which may occur from the incorporation of HIPPS. This should also include flow line sizing, effect of HIPPS on downstream pipeline and riser design, preliminary pressure ratings, HIPPS location, hazard identification, SIS process specification, HIPPS architectures, overpressure philosophy.

7.4 Notes on Pipeline Codes

The HIPPS should be set to protect the pipeline or flowline based on the MAOP definition of the pipeline design code used for the protected line. The use of a HIPPS is otherwise independent of the pipeline design code. Should some regulatory, commercial, or technical driver require it, new pipeline segments, either fortified or protected, could be designed to a code other than that used for existing segments. However, for clarity and consistency, Granherne would recommend that the same code be used for new and existing segments of a system.

Note that API RP 17O makes specific reference to ASME B31 codes for HIPPS piping and components but that design of other parts of the system are not prescribed per the following:

5.4.2.3 Nonstandard Pressure Ratings

All other piping exterior to the HIPPS equipment should conform to the design requirements and piping codes specified by the end user. This requirement applies to portions of a protected system such as manifolds, pipelines, pipeline end terminations (PLETs), and pipeline end manifolds (PLEMs). These systems shall be designed to MAOP and fortified section requirements.

HIPPS is an enabling technology for deepwater, high pressure developments as well as of potential economic benefit for other pipelines requiring large quantities of pipe. For deepwater high pressure developments a limit state design practice such as API RP 1111



is appropriate, especially for flowline design. A more prescriptive code such as ASME B31.4 or B31.8 may be used where mandated by law, where simplicity of design is beneficial and the design conditions common, or perhaps where customary. HIPPS technology may be appropriate in any of these scenarios.

Some provisions in API RP 17O deal with fortification of certain pipeline and flowline segments of a HIPPS protected system. While design of the segments can be accomplished using the available pipeline codes, neither the pipeline standards nor API RP 17O give prescriptive definition of the ratios of strength between fortified and non-fortified segments. This determination must currently be done on a case by case basis. The determination should consider potential statistical variation in pipe parameters that result from applicable pipe manufacturing standards and project specifications. See further discussion of this topic in Section 6.

The referenced flowline versus riser burst document also notes that the risers generally have a higher minimum burst strength requirement than pipelines. This is true independent of which code or practice is used although the degree of difference can vary. The document also illustrates the required minimum strength difference in one graph with curves for both API 1111 and ASME B31.4 burst criteria.

A brief summary of some of the differences in the API vs. ASME codes follows from the standpoint of design against pipe burst, the failure condition against which a HIPPS is also used.

API 1111 designs against the burst limit state and then defines the allowable pressure in the pipeline or riser as a fraction of this burst pressure. The following figure is extracted from API 1111 showing this relationship.

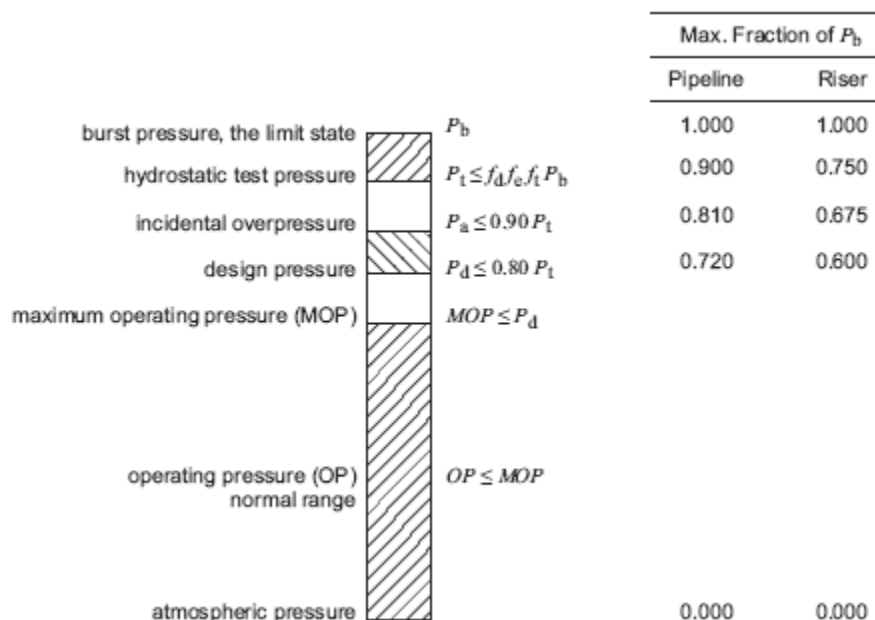


Figure 7-3 API 1111 Pressure Relationships

These limits are paired with corresponding burst hoop stress formulas that have been selected to be accurate over a wide range of diameter to wall thickness ratios. The resulting combination is intended to result in a consistent level of safety for all cases. API bases the analyses on net pressure, i.e. internal minus external. Note the API design factors have been based on statistical analysis of numerous tests on a wide variety of pipe and are intended to be very conservative for offshore locations.

ASME B31.4 and 31.8 design only against pipe yield. The yield to burst relationship is not necessarily consistent. (API handles this by considering both yield and ultimate tensile strength parameters in the analyses.) Thus the degree of safety can vary depending on the stress strain relationship of the steel pipe. ASME also considers net pressure but may define hydrotest pressures differently.

The ASME B31 hoop stress formulas traditionally assume thin wall pipe and use the outer diameter of the pipe. The use of the outer diameter is conservative and the equation becomes increasingly conservative for thick pipe walls. These assumptions are not as consistent as those made by API and lead to over conservative and less economical designs at high pressures. Note that the late 2007 edition of B31.8 appears to address these concerns with an alternative equation but some investigation (as well as a typographical correction now issued as part of the errata) would be needed to determine how this compares to the API formulations.



The design factors for ASME are similar to those for API with B31.8 being somewhat more conservative for gas risers as tabulated below.

Table 7-3 ASME B31 Hoop Stress Design Factors

| Code | Pipeline Factor | Riser Factor |
|--------------------|-----------------|--------------|
| ASME B31.4, Liquid | 0.72 | 0.6 |
| ASME B31.8, Gas | 0.72 | 0.5 |

Note that ASME B31.8 specifically excludes “flow lines” upstream of the trap or separator and B31.4 similarly excludes “production” facilities although this does not necessarily invalidate the design approach for flowlines from a well to a facility and adequate vagueness exists in the definitions that these codes can be considered. API 1111 on the other hand specifically includes all offshore pipeline categories.

Note that with respect to pipe both ASME B31.8 and B31.4 have offshore sections that recognize the differences between conventional and underwater use. ASME B31.3 on the other hand does not and is primarily intended for usages in facilities much different than those found subsea. For this reason it is suggested that where API 17O makes reference to B31 codes, that B31.8 might be considered the more applicable one, especially for pipe, with B31.3 used in special cases not adequately addressed by B31.8.

Note also that when we consider other limit states that may be relevant to a HIPPS protected pipeline system in deep water, pipe collapse in particular, the B31 codes give little guidance or refer to API 1111.

Given the above, API 1111 is recommended as the design code of choice when using a HIPPS for flowlines, risers or pipe in agreed flowline components such as jumpers or PLEMs.